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Potential for Cogeneration of Heat and Electricity in California Industry - Phase II

H. S. Davis, et al

Jet Propulsion Laboratory
Pasadena, California

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A. K. Kashani
M. L. Slonski

January 1, 1979

Prepared for
U.S. Department of Energy
by

Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

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Prepared by the Jet Propulsion Laboratory, California Institute of Technology, for the U.S. Department of Energy by agreement with the National Aeronautics and Space Administration.

FOREWORD

This report summarizes the results of a Phase II study conducted by the Jet Propulsion Laboratory for the Department of Energy to analyze the nontechnical issues of industrial cogeneration for 12 industrial firms in California. The issues, identified by these firms in the Phase I study, are institutional, environmental, and economic.

The project manager was Herbert S. Davis. The key participants and their primary areas of responsibility were as follows:

Edward Edelson, institutional and environmental issues
Ali K. Kashani, environmental regulations and constraints
Marie L. Slonski, economic analysis

The duration of the study was approximately eight months and involved 16 man-months of effort. The project coordinators were Alan J. Streb, Department of Energy, Headquarters, and Terry Vaeth, Department of Energy, San Francisco Operations Office.

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City of Santa Clara, California
Environmental Protection Agency - Region IX
Pacific Gas and Electric Company
San Diego County Air Pollution Control District
South Coast Air Quality Management District
Southern California Edison Company

We also wish to thank R. Anglin, E. S. (Ab) Davis, and R. O'Toole for reviewing a preliminary version of this report and for making helpful suggestions.

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ABSTRACT

The nontechnical issues of industrial cogeneration for 12 California firms are analyzed under three categories of institutional settings: (1) industrial ownership without firm sales of power, (2) industrial ownership with firm sales of power, and (3) utility or third party ownership. Institutional issues are analyzed from the independent viewpoints of the primary parties of interest: the industrial firms, the electric utilities and the California Public Utilities Commission. Air quality regulations and the agencies responsible for their promulgation are examined, and a life-cycle costing model is used to evaluate the economic merits of representative conceptual cogeneration systems at these sites. Specific recommendations are made for mitigating measures and regulatory action relevant to industrial cogeneration in California.

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SECTION I

EXECUTIVE SUMMARY

A. BACKGROUND

Current trends suggest that California industry and electric utilities will require substantial quantities of fuel oil and natural gas in the future to meet their energy needs. Construction of industrial cogeneration plants over the next 5 to 10 years, along with shifts in fuel use from gas and oil to coal, can lead to more efficient use of these scarce fuels, reduced capital and operating costs, and significant reductions in the lead-times now required for large electric utility plants.

Cogeneration is generally recognized as a proven technology with demonstrated benefits. The industrial firms surveyed, however, indicated that significant institutional, environmental, and economic issues must be resolved before they will regard the concept as desirable. The objective of the present study is to analyze these issues in order to assist the federal government and the State of California in making policy decisions in matters relating to cogeneration.

The diversity of institutional issues identified by the surveyed firms suggests that industrial cogeneration can be meaningfully analyzed by independently examining the following three categories of institutional settings:

<u>Category A: Industrial Ownership Without Firm Sales of Power</u>

(1) The industrial firm owns and operates the cogeneration system.

(2) The cogeneration system partially satisfies the firm's electrical demand.

(3) Additional power, if required, is purchased from an electric utility.

(4) Excess by-product power, if and when available, is sold to the utility.

(5) Standby power is purchased from the utility.

<u>Category B: Industrial Ownership with Firm Sales of Power</u>

(1) The industrial firm owns and operates the cogeneration system.

(2) All cogenerated power or excess by-product power is sold to the utility as firm power.

(3) The industrial firm purchases all its required power from the utility.

Category C: Utility or Third Party Ownership

(1) The utility company or a third party owns and operates the cogeneration system.

(2) The industrial firm purchases both steam and electricity from the utility or third party.

As a result, the issues, both institutional and environmental, as well as the economic considerations are seen to apply in different degrees for different categories of industrial cogeneration.

B. OBSERVATIONS AND CONCLUSIONS

Based on the results of this study, the following observations and conclusions are made relative to industrial cogeneration in California:

(1) Industrial firms with captive energy sources have greater opportunities for economically viable cogeneration systems than those using purchased fuels.

(2) Because of the delay in enacting the National Energy Act, the provisions of that Act directed at encouraging cogeneration have in fact had the opposite effect.

(3) California's three major investor-owned electric utilities have widely divergent views on industrial cogeneration, particularly with respect to incorporating cogeneration capacity into their resource planning and establishing a price for purchasing cogenerated power.

(4) Air quality regulations, particularly the New Source Review (NSR) rules, do not recognize the potential of industrial cogeneration to reduce air pollution and conserve energy.

(5) A favorable purchase price for excess by-product power is not as critical an issue as industry perceives it to be. The majority of cogeneration systems considered in this study did not produce excess by-product power; those that did had relatively low calculated break-even prices for its sale.

(6) The economic viability of industrial cogeneration with utility or third party ownership is highly sensitive to the price charged for process steam.

(7) Assuming applicable corporate discount rates, after taxes, of between 10% and 15%, conceptual cogeneration systems with lower life-cycle costs than the corresponding base (non-cogenerating) systems were identified for 9 of the 12 industrial firms considered in this study.

(8) Assuming 100% financing, a 6% interest loan is a greater incentive than a 20% investment tax credit for cogeneration projects larger than about 1 megawatt. However, neither form of incentive is effective for cogeneration projects that would not be viable without these incentives.

C. RECOMMENDATIONS

The intent of the following recommendations is to respond to the concerns, expressed or implied, of the representatives of the organizations interviewed during the course of this study. Appropriate local, state, or federal authorities should consider:

(1) Passing legislation clearly exempting industrial cogenerators from regulation as public utilities.

(2) Clarifying their position on changes in natural gas priorities for industrial cogenerators.

(3) Encouraging utility or third party ownership as well as industrial ownership of cogeneration facilities.

(4) Defining the required trade-off ratios for different pollutants in different regions.

(5) Allowing an emissions credit for industrial cogenerators based on the number of kilowatt-hours of utility energy displaced.

(6) Developing and maintaining a list of best available control technology (BACT) and/or a set of guidelines for evaluating individual industrial cogeneration projects.

(7) Expanding the concept of trade-offs to include cross-pollutant and inter-basin trade-offs.

(8) Analyzing in detail the economic viability of industrial cogeneration using an analytical model that can simulate the computation of rates and load fluctuations on a daily or even an hourly basis.

SECTION II

INTRODUCTION

A. BACKGROUND

Three major national studies (References 1, 2, 3) have estimated that industrial cogeneration* can provide both substantial fuel savings and reductions in the required capital expenditures for the generation of electrical power. In an effort to understand the implications of these study results for the State of California, a two-phase study was initiated by the Jet Propulsion Laboratory for the California Energy Commission and the U.S. Department of Energy. The primary effort of the first phase (Reference 4) was a survey of 12 representative, major energy-consuming industrial firms in California (see Table 2-1). The information collected was organized into four categories: technical, economic, environmental, and institutional. The technical aspects of cogeneration systems were analyzed for each site using topping or bottoming cycles. These conceptual alternative systems were then compared to a base (non-cogenerating) system for which thermal and electrical energy is purchased to meet each plant's demand. The results of this technical analysis showed that substantial energy savings, relative to existing plant operations, could be achieved with cogeneration systems. The results of the industrial survey indicated that while near-term implementation of industrial cogeneration is technically feasible, significant institutional, environmental, and economic issues must first be resolved before industry will regard the concept as desirable.

B. APPROACH

The issues associated with industrial cogeneration may be real or perceived, depending on the institutional setting. For example, regulation by the Public Utilities Commission of an industrial firm that sells cogenerated power can be discounted by considering utility ownership of the cogeneration facility. Utility ownership, however, raises other issues. The approach used in this report first defines the ownership arrangement of the cogeneration system and then examines the associated institutional and environmental issues. This approach also simplifies the discussion of the economic considerations related to industrial cogeneration, particularly the selling and purchase prices of cogenerated power.

*See Appendix A for definitions of this and other relevant terms.

Table 2-1. Selected Cogeneration Sites in California

Industrial Firm	Industry	Location	Type Cogeneration Cycle: Topping	Type Cogeneration Cycle: Bottoming	Air Pollution Control District	Electric Utility: PGE	Electric Utility: SCE	Electric Utility: SDGE	Electric Utility: Municipal	Cogeneration Study: Existing	Cogeneration Study: Planned	Cogeneration Study: Under Study	Thermal Energy Use Rank In California	Reported Estimate of Cogeneration Capacity, MWe
California Paperboard Corp.	Paperboard Products	Santa Clara	X		Bay Area				X		X		46	10
California Portland Cement Co.	Cement Manufacturing	Mojave		X	Kern Co.		X					X	3	100
Exxon Co., U.S.A.	Petroleum Refining	Benecia	X		Bay Area	X						X	1	40
Hunt-Wesson Foods, Inc.	Food Products	Fullerton	X		South Coast		X				X		6	0.7
Husky Oil Co.	Enhanced Oil Recovery	Santa Maria	X		Santa Barbara Co.	X						X	1	300
Kaiser Steel Corp.	Steel	Fontana	X		South Cost		X					X	4	60
Kelco Co.	Organic and Inorganic Chemicals	San Diego	X		San Diego Co.			X			X		2	12
Owens-Illinois, Inc.	Glass Containers	Oakland		X	Bay Area	X						X	7	---
Simpson Paper Co.	Pulp and Paper	Anderson	X		Shasta Co.	X					X		46	19
Simpson Timber Co.	Timber	Arcata	X		Humboldt Co.	X						X	20	---
Spreckels Sugar Co.	Sugar Beet Refining	Manteca	X		San Joaquin Co.	X				X			5	4.2
Union Oil Co.	Petroleum Refining	Wilmington	X		South Coast				X			X	1	40
Totals			10	2	---	6	3	1	2	1	4	7	---	---

Through a review of the literature, meetings with the electric utilities and the California Public Utilities Commission, a number of institutional settings appropriate to industrial cogeneration were identified. From this list, three major categories of industrial cogeneration were selected for use in this report and are described here:

Category A: Industrial Ownership Without Firm Sales of Power (Section III)

(1) The industrial firm owns and operates the cogeneration system.

(2) The cogeneration system partially satisfies the firm's electrical demand.

(3) Additional power, if required, is purchased from an electric utility.

(4) Excess by-product power, if and when available, is sold to the utility.

(5) Standby power is purchased from the utility.

Category B: Industrial Ownership with Firm Sales of Power (Section IV)

(1) The industrial firm owns and operates the cogeneration system.

(2) All cogenerated power or excess by-product power is sold to the utility as firm power.

(3) The industrial firm purchases all its required power from the utility.

Category C: Utility or Third Party Ownership (Section V)

(1) The utility company or a third party owns and operates the cogeneration system.

(2) The industrial firm purchases both steam and electricity from the utility or third party.

This report is structured around these three categories of institutional settings. The relevant institutional and environmental issues, as well as the relevant economics, are discussed for each category in order to provide the reader with a clearer understanding of the ramifications of industrial cogeneration for these 12 California firms.

C. INSTITUTIONAL ISSUES

The 12 industrial firms that were surveyed identified nine issues that were categorized as institutional. The diversity in the identification of issues can be seen in Table 2-2. This diversity implies that either:

(1) The firms' level of understanding of the institutional issues is embryonic, or

(2) Each firm faces a very different institutional environment and, hence a unique set of institutional issues.

The institutional issues in this report are discussed, within each category, in the order of their relevance -- whether they are primary, secondary, or inappropriate (see Table 2-3). When appropriate, the discussion includes the points of view of the institutions with primary decision making responsibility, i.e., the industrial firm, the local electric utility, and the California Public Utilities Commission (PUC).

In January 1978 the PUC took what it called a "significant first step" to promote cogeneration by issuing Resolution No. E-1738. This resolution directs electric utilities to augment cogeneration projects by (1) proposing rate schedules for expanding interruptible electric service, (2) proposing other "rate proposals to enhance cogeneration, including revision of standby rates," (3) submitting "guidelines covering the price and conditions for the purchase of energy and capacity from cogeneration facilities owned by others," and (4) submitting a report on guidelines for development of utility owned cogeneration facilities." These are very important steps and demonstrate the active interest of the PUC. (Appendix B provides more detail on the responsibility and authority of the PUC.) The reaction of the electric utilities to this move by the PUC and to the very enthusiastic reports on cogeneration differs markedly from one company to another, even within the state. (Appendixes C, D, E, and F provide more detail on the outlook of the electric utilities.)

D. ENVIRONMENTAL ISSUES

Nine of the 12 firms surveyed identified New Source Review (NSR) as an environmental issue. For example, the City of Santa Clara, owner of the cogeneration equipment located at the California Paperboard Corporation, called the NSR rules the "most critical factor," and Hunt-Wesson indicated that if application of the NSR rules requires them to reduce production in order to install cogeneration, they would not proceed with the project. Union Oil Company also noted that the NSR rules tend to reduce the attractiveness of cogeneration.

For many of the firms, it is not the idea of the NSR rules, regardless of the specific emission limit, which concerns them. Rather, it is the prevailing uncertainty created by the application of the rules. Both Union Oil and Simpson Paper noted the problems created for investment decisions by the ambiguity in the NSR rules.

Table 2-2. Diversity of Institutional Issues Identified by Firms Participating in This Study

Identified Institutional Issues	Industrial Firm												Total Number of Sites Identifying Issues
	California Paperboard Corp.	California Portland Cement Co.	Exxon Co. U.S.A.	Hunt-Wesson Foods, Inc.	Husky Oil Co.	Kaiser Steel Corp.	Kelco Co.	Owens-Illinois, Inc.	Simpson Paper Co.	Simpson Timber Co.	Spreckels Sugar Co.	Union Oil Co.	
Rate for Selling Power		X	X	X					X				4
Standby Power Charge		X							X	X		X	4
Wheeling		X				X				X			3
Natural Gas Priorities	X			X					X				3
Long-Term Agreements	X	X			X								3
Steam Sales	X						X						2
Regulation		X	X										2
National Energy Act		X		X									2
Rate Design												X	1
Number of Issues Identified per Firm	3	6	2	3	1	1	1	0	3	2	0	2	

Table 2-3. Correspondence of Institutional Setting and Institutional Issues

Institutional Setting	Institutional Issues		
	Primary	Secondary	Inappropriate
Category A: Industrial Ownership Without Firm Power Sales	Standby power charge National energy act	Natural gas priorities Rate design	Rate for selling power Long term agreements Steam sales Regulation Wheeling
Category B: Industrial Ownership With Firm Power Sales	Rate for selling power Regulation Long term agreements	Rate design Wheeling National energy act	Standby power charge Steam sales
Category C: Utility or Third Party Ownership	Long term agreements Steam sales	National energy act	Rate for selling power Regulation Standby power charge Natural gas priorities Wheeling Rate design

What are these NSR rules that industry is so concerned about? - rules that Tom Quinn, Chairman of the California Air Resources Board (ARB), has characterized as the "single most important" set of air pollution regulations in the state* and which appear to be the only way of confronting the dilemmas of keeping a non-attainment air basin attractive to industry while continuing to improve air quality? NSR rules are one of five air programs implemented by the U.S. Environmental Protection Agency (EPA).** The Clean Air Act of 1970 explicitly recognizes that emissions limitations alone are not sufficient in non-attainment areas to attain and maintain air quality standards. In formulating its 1971 basic guidelines for the content of state implementation plans,*** EPA stated that "other measures necessary to insure" achievement and maintenance of the ambient air quality states to implement regulations to subject new air pollution sources to preconstruction review, and to prohibit the construction of a new or modified stationary source which would interfere with the attainment of the air quality standards. This then is the underlying rationale of NSR rules: attainment of ambient air quality through control of point sources. The complete text of the original model NSR rules (Rule 213) for California appears in Appendix G.**** Appendix H contains additional background information on NSR rules as well as other environmental regulations that can affect the implementation of cogeneration.

The environmental sections of this report concentrate on the interpretation and application of the NSR rules. Industrial firms have already expressed***** their confusion over the way the NSR rules would be applied and their concern that the rules would inhibit investment in industrial cogeneration. As with the other issue areas discussed in this report, institutional and economic, the subject matter cannot be considered in isolation. Meeting the NSR requirements implies increased costs associated with the cogeneration investment. Simpson Paper, for example, anticipated that 25% of the capital cost of its cogeneration project would be directed towards complying with environmental regulations. Such costs can be considered either as an environmental barrier or as an economic barrier. The emphasis here is on describing the environmental regulations that will give rise to such costs.

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*ARB Bulletin, January 1978.

**The five programs are (1) existing sources, (2) new source performance and standards (NSPS), (3) new source review (NSR), (4) prevention of significant deterioration (PSD), (5) natural emission standards for hazardous air pollutants (NESHAP).

***40 CFR 51.18.

****As discussed in the text, several modifications have already been made to the model rule by the California Air Resource Board.

*****The interviews with the 12 firms performed earlier in this study occurred prior to the Clean Air Act Amendment of 1977. More concern might now exist for other provisions, e.g., the application of the prevention of significant deterioration program.

Understanding industry's concern about the NSR rules requires some background on the environmental regulators: the U.S. Environmental Protection Agency (EPA), the California Air Resources Board (ARB), and the local Air Pollution Control Districts (APCD).* The EPA sets national standards; the ARB is responsible for ensuring that state programs are established to meet these standards. Local agencies have the primary responsibility for the design and enforcement of programs that relate to stationary sources.** The interrelationships of these agencies in dealing with a request for a permit to construct a cogeneration unit are illustrated in Figure 2-1. Also identified in the figure is the basic legislation involved, the air pollution abatement programs identified by this legislation, and the regulations set up by the enforcement agencies to carry out these programs.

Eventually, all enforcement will be in the hands of the state. However, until the state implementation plan is approved, the EPA retains the responsibility for carrying out the programs shown in the figure. But, as is indicated by the arrows in the figure, a portion of this task has been delegated to the ARB, which has, in turn, delegated it to the APCDs. The EPA retains the responsibility for enforcing the PSD program because the state has not yet set up the necessary regulations. However, PSD applies to a limited number of cases.

Both the EPA and ARB can enter into the permit process when they determine that the district has operated incorrectly. The ARB also becomes involved in a permit decision when it concerns a source which requires an air quality impact analysis (i.e., one which increases emissions by more than 25 lb/hr or 250 lb/day of any of the air contaminants specified under Rule 213). In these cases, both the ARB and the EPA must be given notice of the district's intent to issue permits to construct and may submit their comments prior to the actual issuance of the permits.*** Some articles have indicated that the ARB has the "final say" (see Los Angeles Times, "Unique Pact May Finally Pave Way for Oil Terminal," Aug. 18, 1978). This misconception has arisen because the ARB does retain the authority under the California Health and Safety Code**** to review rules and regulations of a district to determine whether they make reasonable provision to achieve and maintain state air quality standard. The ARB has used this authority for implementing NSR rules in both the South Coast Air Quality Management District and the Bay Area Air Pollution Control District. Table 2-4 shows the status of the New Resource Review rules in the APCDs of interest to this study.

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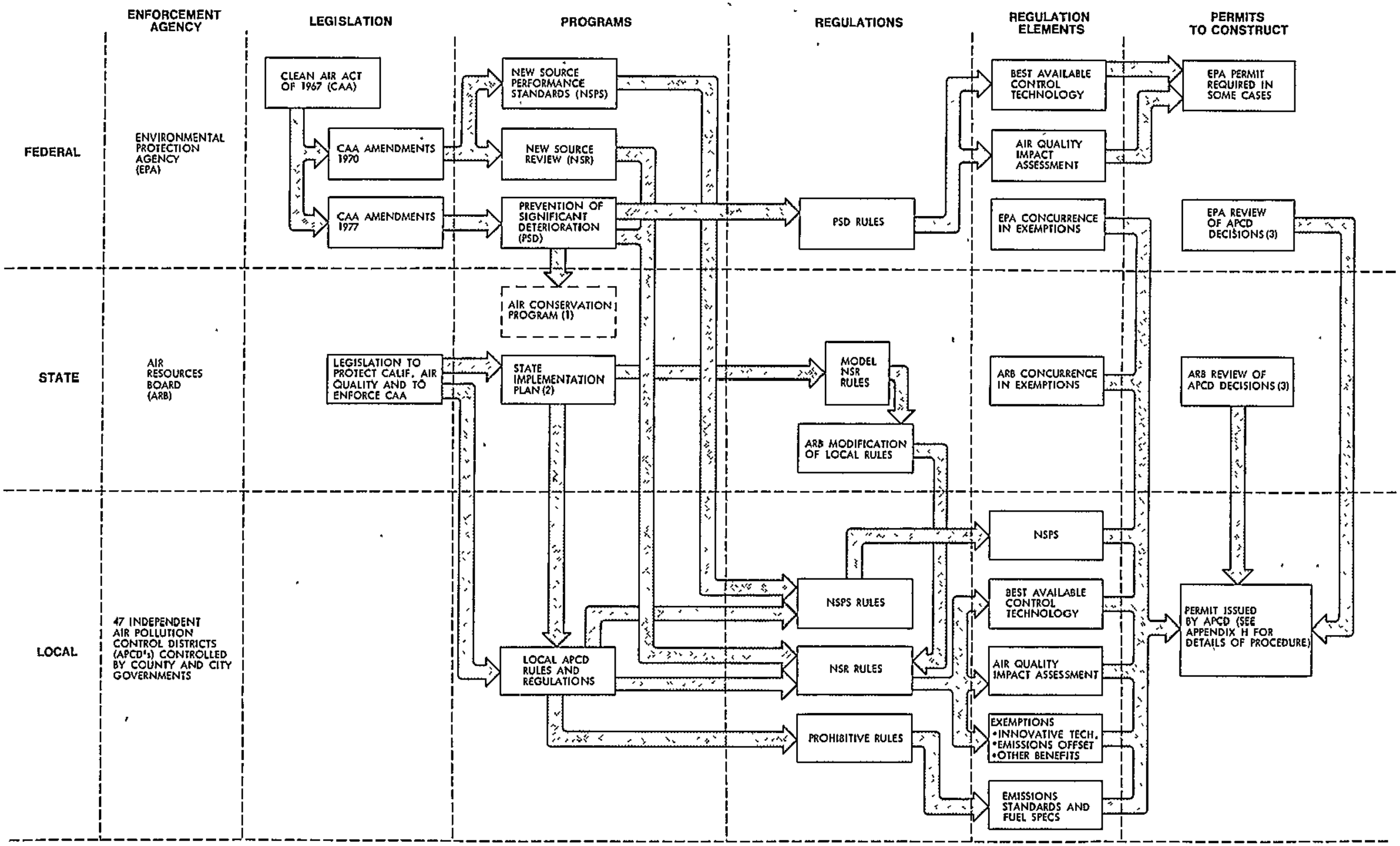
*The local air pollution agency in Southern California is the South Coast Air Quality Management District. However, APCD is used in this report to indicate the local authority.

**The ARB is responsible for the enforcement of non-stationary source programs.

***R. J. MacKnight, South Coast Air Quality Management District, personal communication, Dec. 20, 1977. Note, however, that some of the exemptions specified in the NSR require EPA and ARB concurrence. For example, the Sohio Oil Terminal is being reviewed under one of the exemption clauses in the NSR rules.

****Paragraphs 41500, 41502, and 41504.



(1) NOT YET IN EFFECT; (2) BEING REVISED; (3) NOT DONE IN EVERY CASE, BUT LIKELY FOR LARGE UNITS.

Figure 2-1. Interrelationship of Air Pollution Control Agencies and Regulations Influencing Issuance of Permits to Construct Cogeneration Units

Table 2-4. New Source Review Status for Air Pollution Control Districts in This Study

APCD	Date Adopted by ARB	Date Adopted by APCD	Major Problems
Bay Area	12/20/77*	---	---
Santa Barbara Co.	1/26/77	---	---
South Coast AQMD	10/08/76	---	---
Kern Co.	---	12/28/76	No BACT requirements Definition of stationary source differs from ARB
San Joaquin Co.	---	6/21/77	No BACT definition ARB disagrees with definition of stationary source Cutoff is 100 tons/year rather than hourly and daily
Shasta Co.	---	10/15/74	No BACT requirements or definition No trade-off provisions No definition of stationary source Cutoff is 25 tons/year rather than hourly and daily
Humboldt Co.	---	6/13/76	No allowance for trade-offs Definitions of BACT and stationary source differ from ARB
San Diego Co.	---	11/04/76	ARB disagrees with definition of BACT

*Also approved by EPA.

In this report, the NSR rules have been divided so that the sections most appropriate to each cogeneration category are discussed in that chapter. Under Category A - industrial ownership without firm power sales (Section III) - the best available control technology (BACT) provision of the New Source Review rule is discussed. It has been assumed that proposals considered in Category A involve no more net emissions but are just modifications of existing facilities. Under Category B - industrial ownership with firm power sales (Section IV) - the Air Quality Impact Analysis provision is discussed. Here, it is assumed that the modification necessary for industrial cogeneration will result in increased fuel usage and therefore an increase in the net emissions from the stationary source. The discussion of BACT in Section III is also applicable in this section. Under Category C (Section V) the local electric utility owns the cogeneration equipment and it is the utility, then, rather than the industrial firm that becomes involved in obtaining the required air pollution control permits. However, in some cases the firm can become involved because of the need for trade-offs under the Air Quality Impact Analysis.

E. ECONOMIC CONSIDERATIONS

The life-cycle cost approach used in this report (described in Appendix I) computes the present value, for a specified year, of all costs included in the purchase, installation, and operation of a particular system. This approach "collapses" a distribution of cash flows over the system lifetime into a single number by taking into account the time value of money, and thus allows a cost comparison of various systems. All system costs and financial obligations, including income taxes, depreciation, non-income taxes, insurance, and other capital related charges are included in this approach and are described in Appendix J. The analysis is treated only from the viewpoint of each industrial firm and not from the viewpoint of the utility or a third party.*

The internal rate of return for a project is defined as that discount rate at which the net present value is equal to zero. A cogeneration system is not usually expected to generate sufficient revenues to offset all its costs, but rather to reduce costs when compared to a base system. Thus, a cogeneration system is not usually expected to have a positive net present value. However, the incremental cost/revenue difference between a cogeneration system and a base system is expected to result in a positive net present value and the incremental internal rate of return can be determined.

*In particular, this study is not designed to answer the question of whether cogeneration is "desirable" from the social perspective. Such an examination would require a detailed analysis of the impact of cogeneration on utility system costs and a careful environmental tradeoff analysis, neither of which are within the scope of this study.

Two financial incentive schemes, a 20% investment tax credit and a 6% interest loan, were evaluated for each site that required a capital investment for the cogeneration system.* Though neither of these incentives are necessarily recommended, they do provide a good test of the individual investment decisions related to major tax and financial incentives. For the low interest loan, it was assumed that 100% financing would be available; the advantage of this type of financing was incorporated into the life-cycle cost calculation. In each case, the effect of the incentive on the life-cycle cost of the cogeneration system was determined.

A total of 14 economic analyses was performed for the 12 sites.** The breakdown of these analyses for each firm by cogeneration category is shown in Table 2-5. The life-cycle cost analyses of Category A do not include receipts from the sale of by-product power; Category B life-cycle cost analyses do include these receipts. Category C analyses include receipts from steam sales. Site-specific data from these analyses are given in Appendix K.

Estimates of the cost of air pollution abatement equipment are taken from a previous study (Reference 3) and may not be realistic, depending on the application of environmental regulations as discussed in the environmental sections of this report. Nevertheless, the analysis represents a first step in assessing the site-specific costs for implementing industrial cogeneration in California.

*Husky Oil and Spreckels Sugar did not require a capital investment.
**Only those conceptual cogeneration systems developed in Phase I of this study (Reference 4) were analyzed.

Table 2-5. Economic Analysis Performed in This Study

Industrial Firm	Category A: Industrial Ownership Without Firm Power Sales	Category B: Industrial Ownership with Firm Power Sales — Excess Power Sold	Category B: Industrial Ownership with Firm Power Sales — All Power Sold	Category C: Utility or Third Party Ownership
California Paperboard Corp.	X	X	X	X
California Portland Cement Co.	X		X	
Exxon Co., U.S.A.	X		X	
Hunt-Wesson Foods, Inc.	X*	X**	X*	
Husky Oil Co.				X
Kaiser Steel Corp.	X		X	
Kelco Co.	X	X	X	X
Owens-Illinois, Inc.	X		X	
Simpson Paper Co.	X	X	X	
Simpson Timber Co.	X		X	
Spreckels Sugar Co.	X		X	
Union Oil Co.	X		X	

*Three alternatives analyzed.
**Two alternatives analyzed.

SECTION III

ANALYSIS OF CATEGORY A: INDUSTRIAL OWNERSHIP WITHOUT FIRM SALES OF POWER

Under Category A, the cogeneration system meets the plant steam demand and also produces a portion of its own electrical demand. The firm buys standby power from the local utility to back up its cogenerated electrical capacity; additional power, if required, is also purchased from the utility company. All bottoming cycles appear to fit this arrangement.

Of the three, Category A is the most easily implemented because of the available industrial steam loads, and the potential avoidance of environmental issues*, and, as shown in this section, of institutional issues. On the other hand, the least amount of primary fuel savings and the smallest reduction in the delay or avoidance of future capital expenditures for electrical generation are realized.

A. INSTITUTIONAL ISSUES

The determination of the price of standby power is the most important institutional issue because it influences the expected return to the firm from cogeneration. Related to this issue is the effect of changes in the firm's electrical expenses as utilities employ new rate structures. As the firm's payments to the electric utility increase, any investment that offsets the bill will become more important. The lack of a finalized National Energy Act has also been influential. Potential cogenerators are still waiting to see if a tax investment credit is a possibility and what guidelines and rules are going to be prescribed by the Federal Energy Regulatory Commission (FERC).

The price of electricity sold by the industrial firms to the grid does not appear to be an appropriate issue because most of the return to the firm is the result of the reduction in electric bills. Another non-issue is the regulation by the PUC or the FERC. Without the firm sale of electricity to the grid, it would be difficult to consider the industrial firm as an electric corporation or as having dedicated its facilities to the public. There is no concern over agreements with respect to long-term arrangements in the contracts because a firm agreement between the industrial firm and the utility is unnecessary. As a result, the utility will be reluctant to look upon the firm's cogeneration potential as part of its capacity. Because of the need to supply standby power, the electric utility must still plan on the same reserve margin as that required without cogeneration. The amount of reserve might be reduced as the electric utility company recognizes that there is a low probability that all the cogenerators would require standby simultaneously.

*Although bottoming cycles do not increase emissions, the firm might still be required to install BACT to meet the New Source Review rules. See Section III-B.

1. Primary Issues

a. Standby Power Charges. Standby power charges are paid on the basis of the portion of the connected load that is designated standby. This capacity is analogous to the fees paid by a firm for a financial line of credit. For example, if a plant cogenerates 50% of its electrical power, it would like to have that 50% of its capacity on standby from the local utility. Then if its cogeneration facility must be shut down, it can rely on its standby capacity without affecting production. If the price for standby power is too high, firms will be discouraged. On the other hand, if the price is too low then the firm will not be paying its fair share of the capacity required by the utility's system. Other ratepayers would be responsible for the difference.

The Industrial Firm's Viewpoint

Simpson Timber Company pointed out that the problem lies in trying to establish a standby charge that is mutually acceptable to them and to Pacific Gas and Electric Company (PG&E). Union Oil Company noted that the cost and availability of standby power is an important factor and could greatly influence the profitability of its cogeneration project.

Simpson Paper Company felt that the current PG&E rate for standby service was too high. California Portland Cement Company was more open-minded in its approach of what would be a "favorable" charge although they did point out that any cogeneration agreement with the utility would depend on obtaining such a favorable charge. One reason that standby charges for cogeneration might be excessive is that the utility views each kilowatt of standby capacity independently. If five firms each required 10 kW of standby capacity, the utility charges for a total of 50 kilowatts of standby capacity. The likelihood of all five firms demanding their standby power simultnaeously is an event that can be described by some probability distribution. If the capacity of the industrial firms is aggregated and reduced to the statistical maximum likelihood of standby capacity required, the amount to be paid by each industrial firm for standby would be reduced.

The Electric Utility's Viewpoint

The existing standby charges for the three public utilities discussed in this report are as follows:*

Utility	Standby Charge for:	Per Meter Per Month
PG&E	First 25 kW of contract capacity	\$2.74/kW
	Next 100 kW of contract capacity	2.08/kW
	Over 124 kW of contract capacity	1.64/kW
SCE	First 20 kW of contract demand	2.00/kW
	All excess kW of demand	1.50/kW
SDG&E	First 20 kW of contract demand	3.44/avg kW
	All excess kW of demand	2.74/kW

*Reference 5, p. 15.

Each utility values standby somewhat differently. The utilities maintain that they have set these rates to assure that their other customers are not subsidizing those on standby. With rising construction costs, the provision of standby power, upon request, can be expensive. If those firms utilizing standby do not pay for the utility's investment in extra capacity, the other ratepayers will be forced to finance the investment.

The PUC has requested these three utilities to provide revisions to their standby rate. "SCE's and SDG&E's standby tariffs already have exemption clauses which permit the customers to operate in parallel (as required by some cogeneration systems) with the utility system without paying standby charges. PG&E's standby tariff does not provide for the exemption." (Reference 6, pg. 14.) The PUC resolution on cogeneration states that "Rates for standby service and prices paid for energy purchased from cogeneration <u>may not</u> be appropriate to stimulate the development of potential projects." (Reference 7; emphasis added.)

The utilities felt that the standby issue was artificial. Most of their customers, according to the utilities, view standby as a form of insurance. Because the alternative is for the firms to install twice the required capacity to provide their own standby, the insurance is considered by many firms to be reasonable.

<u>Summary</u>

Industrial firms considering cogeneration appear to feel that the standby charge will not be established at a rate favorable to their interests. Utilities are changing their perception of standby as a result of the PUC resolution.

Standby, however, is not a charge for a fictitious product. The issue is how that charge is determined and how much of the product a cogenerator or a group of cogenerators require. These are questions related to system reliability and utility accounting which have been, and will remain, debatable topics.

b. <u>The National Energy Act</u>. During the industry survey, the National Energy Act was referred to as an institutional constraint. Considering that this legislation has been under discussion for over a year and that legislation on cogeneration and electric utility rate reform and regulatory improvement have been discussed in the U.S. Congress for several years, such legislation appears to fit a working definition of an institutional issue. The relevant aspects of the National Energy Plan and the early legislation are discussed in detail below to provide the reader with an understanding of the legislative issues. One important example is the definition of cogeneration.

In President Carter's National Energy Plan, cogeneration was selected as a major portion of the plan for promoting conservation and energy efficiency. The plan notes that a "variety of institutional barriers impede (cogeneration's) development," even though it is economical today. Therefore:

"A Program is proposed to remove these barriers by assuring that industrial firms generating electricity receive fair rates from utilities for both the surplus power they would sell and for the backup power they would buy. Industries using cogeneration to produce electricity could be exempted from State and Federal public utility regulation, and would be entitled to use public utility transmission facilities to sell surplus power and buy backup power. ... Finally, industrial firms and utilities which invest in cogeneration equipment could be exempted from the requirement to convert from oil and gas in cases where an exemption is necessary for cogeneration." (Reference 8, pg. 45.)

In the legislation proposed to establish a comprehensive national energy policy, a cogeneration facility was defined as

"A facility which produces —

(a) electric energy and

(b) other forms of useful energy (such as steam or heat) which is, or will be, used for industrial, commercial or space heating purposes." (Reference 9, see 107 (b)(1).)

A "qualifying cogeneration facility" was defined as

"a cogeneration facility which the (Federal Power) Commission determines —

(a) meets such requirements respecting minimum size and fuel efficiency as the Commission, by rule prescribes; and

(b) in the case of a cogeneration facility which is, or will be, directly connected to an electric utility, the owner or operator of such facility has offered such utility an opportunity to construct and operate such facility on terms which are agreed upon by the parties." (Reference 9, see 107 (b)(2).)

The earlier legislation required the Federal Power Commission (FPC)* to "prescribe rules requiring electric utilities to offer to sell electric energy to the owner or operator of a qualifying cogeneration facility and to offer to purchase electric energy from such owner or operator." (Reference 9, Section 107 (a).) These rules were to be completed within two years after the date of enactment of the bill. Several other rulings related to cogeneration, and addressed later in this section, were also to be prescribed by the FPC.

*The Federal Energy Regulatory Commission (FERC) has since assumed these planned responsibilities.

Hearings on the legislation demonstrated several concerns. A representative of Houston Lighting and Power Company felt the bill was inflexible in regard to allowing electric utility ownership of cogeneration facilities. (Reference 10, page 326.) On the other hand, others felt that "the specific definition of qualified cogenerators will prevent any enthusiastic response by industry" because it pays "too much deference to utility company interests." (Reference 10, pages 332 and 335.)

In the summer of 1977, both Senate and House versions of bills related to cogeneration were voted on and sent to conference. Although no bills have been issued from the conference (it is customary that bills are not issued separately but as a complete package), a significant amount of work has been completed on two bills that relate to cogeneration. They are H.R. 5146 on coal conversion and H.R. 4018, which discusses the Public Utilities Regulatory Policy Act of 1977.

The November 21, 1977 draft (approved by the conferees) of the major provision of H.R. 5146 discusses exemptions from coal conversion for major fuel-burning installations and electric power plants:

> "Permanent exemptions are to be granted for new cogeneration electric power plants or major fuel-burning installations where its economic and other benefits cannot be obtained with coal or other fuels." (Reference 11, page 12.)

H.R. 4018 addresses several issues related to cogeneration including wheeling and interconnection as well as cogeneration itself. The definition used for a "cogeneration facility" is:

> "A facility owned by a person not primarily engaged in the generation or sale of electric power. ..., which facility produces (A) electric energy, and (B) other forms of useful energy (such as steam or heat) which is or will be used for industrial, commercial or space heating purposes."
> (Reference 12, Section 113 (d)(1).)

The definition excludes utility-owned cogeneration plants from qualifying under this act even though a clause in the definition states "that nothing in this section is meant to prevent utilities from producing electricity by cogeneration." This is not very significant because the bill does not provide any incentives that are useful for an electric utility.

A qualifying cogeneration facility is still a loosely defined concept. The qualification of size, fuel use, and fuel efficiency are to be prepared by the Federal Power Commission after the legislation is enacted.

The most notable change from the original legislation is that guidelines, as opposed to rules, are to be developed by the Secretary of Energy. Specifically, within one year of enactment the Secretary of Energy is required to:

(1) "... recommend to the State regulatory authorities guidelines requiring where he deems appropriate, electric utilities to offer to sell electric energy to any qualifying cogenerator ... and to offer to purchase electric energy from such cogenerators ..."

(2) "... prescribe rules exempting qualifying cogenerators ... in whole or in part from the Federal Power Act and for the Public Utility Holding Company Act, if the Administrator determines such exemption is necessary ... provided, however, that power producers <u>of over thirty megawatts may not be exempt from the Federal Power Act</u>; and provided further that a <u>Federal license must still be required under the Federal Power Act</u>, regardless of whatever other exemptions may be granted." (Emphasis added.)

(3) "... recommend to State regulatory authorities guidelines for the purpose of preventing utilities from engaging in any conduct which results in unreasonable or discriminatory rates or pricing structures or practices against consumers that utilize power facilities or sources other than those provided or otherwise supplied by any such utility." (Reference 9, Section 113.)

Thus it appears that the Federal government still intends to play a major role in the implementation of cogeneration.

In addition to the rules and guidelines listed above, the act calls for "a full and complete analysis of the economics, social, environmental and technological feasibility and consequences of implementing, on a nationwide scale, various waste heat energy recovery and use techniques." (Reference 12, Section 115.)

Other aspects related to cogeneration include:

(1) Interconnection - Federal Energy Regulatory Commission can "direct an electric utility to establish physical connection of its transmission facilities with the facilities of any other electric utility or qualifying cogenerator." (Reference 12, Section 122 (a).)

(2) Wheeling - an electric utility can be ordered to wheel by the FERC if it finds that such action is in the public interest. (Reference 9, Section 241.)

Two of the firms surveyed expressed concern with the legislation. Both firms indicated a desire to wait until the legislation is finalized before making a decision on cogeneration. The legislation indicates that the FERC will play a significant role in determining who qualifies as a cogenerator. It is ironic that the cogeneration provision directed at encouraging cogeneration has had the opposite effect because of the delay in enacting the legislation. Even after the bill is finalized, it could be another year before the FERC prescribes its guidelines on cogeneration.

2. Secondary Issues

a. Natural Gas Priorities. All users of natural gas receive their fuel on a priority basis established by the PUC. The lowest priority (priority 5) is for electric power plants, with industrial firms generally at a higher priority (see Table 3-1). The questions are: If a firm uses natural gas to provide its process heat before installing a cogeneration system, should its priority status be lowered if it also uses natural gas in its cogeneration equipment? Would the change in priority depend on whether it sells electricity to the utility or whether all the electricity is used in-plant?

The Industrial Firm's Viewpoint

Several of the firms expressed concern over the lack of clarification on the answers to the above questions.* California Paperboard Corporation was concerned about a change from their present priority; Hunt-Wesson Foods, Inc., was also concerned, but they indicated that their concern goes beyond cogeneration. A fuel shortage during the canning season could severely impact the firm. Therefore, if the PUC granted them a higher priority if they cogenerate, Hunt-Wesson Foods, Inc., would have a large incentive.

The Public Utilities Commission's Viewpoint

The Public Utilities Commission (PUC) has the authority to establish, and therefore to modify, the priorities for delivery of natural gas. Natural gas priorities could be used as an incentive; that is, a firm that cogenerates could receive a higher priority than it would if it were not cogenerating. The PUC, however, has not taken any related actions.

The role of the federal government dominates the future of natural gas. The Natural Gas Act gives the FERC almost complete control over natural gas activities. Therefore, state action, especially in California, a state that imports must of its natural gas, is quite limited. However, at the federal level, the efforts to modify natural gas activities are directly tied to the National Energy Act legislation.

*Simpson Paper Company was not concerned about this issue since it expects 100% curtailment within five years. Owens-Illinois also expressed some concern over future curtailments of natural gas.

Table 3-1. Natural Gas Priorities
(Effective May 31, 1976)

Priority 1	Domestic customers, small commercial and institutional customers, and small industrial customers using less than 100 Mcf of a peak day and who are presently on firm service.
Priority 2A	Institutional, commercial, and industrial customers with peakday usage greater than 99 Mcf who are presently firm customers; electric utility start-up and igniter fuel; feedstock customers - gas used in the production of ammonia, hydrogen, and methanol.
Priority 2B	Customers who currently have the standby capability to use LPG, including the following major industries: Glass container industry, automobile industry, metals industry, fruit and vegetable dehydration, that portion of the petroleum refineries use that is required for equipment which is not presently capable of using fuel oil - primarily feedstock and cracking equipment.
Priority 3	Commercial and institutional customers with a present capability of using fuel oil (primarily boiler fuel) Industrial users for equipment other than industrial boiler fuel. Includes portions of equipment in: chemical industry, petroleum refineries, and glass industry.
Priority 4	Industrial boiler fuel - includes partial or total requirements in: sugar refineries, petroleum refineries, paper industry, chemical industry, food processing industry, lumber industry, and cement plants.
Priority 5	Steam-electric plants and electric utility gas turbines.

One part of the National Energy Act concerned with natural gas provides for special treatment for firms that cogenerate: H.R. 5146, the Natural Gas and Petroleum Conservation and Coal Utilization Policy Act of 1977, described those facilities which must convert to coal. This legislation has not yet been issued from conference, but by the end of 1977 the conferees had agreed to a permanent exemption for "new cogeneration electric power plants or major fuel-burning installations where its economic and other benefits cannot be obtained with coal or other fuels." (Reference 11, pg. 12.) If such an exemption is not approved, any discussion of changes in natural gas priorities might become moot as major fuel-burning installations are forced to convert to coal.

Summary

The natural gas issue is part of a larger problem facing industry - the uncertainty over the price and availability of fuel. A change in either that could adversely affect the firm's fuel supply will be avoided. The PUC realizes this and has indicated that natural gas availability may be used as an incentive to cogenerate.

Admittedly, there is some subjectivity to the assignment of natural gas priorities. However, to modify the scheme just to encourage one technology only increases the arbitrariness. If cogenerators receive special attention, will that not open the door to other firms seeking an increase in their priority?

On the other hand, decreasing the natural gas priority of a cogenerator where the sale of electricity is a small percentage (if any) of its total sales also appears to be discriminatory despite the fact that such action could be considered a literal interpretation of the priority table. Because of the possibility of such an interpretation, the firms perceive a need for PUC clarification of natural gas priorities for cogenerators.

b. Rate Design

> "Regulators are examining electric utility rate designs and load controls more closely than ever before because of dramatic changes in the economy -- particularly the inflation of plant construction costs and higher fuel costs for generation. State commissioners are asking how well various load management approaches serve the objectives of rate-making in light of these changes. Moreover, because of fundamental shifts in society's concerns about such issues as conservation, some regulators are questioning the relative importance of various and conflicting objectives." (Reference 13, page 9.)

This introduction to the Electric Utility Rate Design Study is an example of the dynamic nature of the PUC's recent concern over new rate designs including lifeline rates and time-of-use pricing. What effect will rate design changes have on the motivation of industrial plants to consider cogeneration? The answer will depend on the rate design established and on its effect on the price of electrical power to large industries.

Only Union Oil, served by the Los Angeles Department of Water and Power (LADWP), raised this issue. The LADWP has recently gone through a review of its rate design (Reference 14). The Mayor's Blue Ribbon Committee recommended that a flat time differentiated rate block rather than a declining rate structure be adopted. The PUC has already ordered time-of-use rates and lifeline rates for the investor-owned utilities under its jurisdiction.

Such price increases can only help motivate an industrial firm to consider energy conservation techniques such as cogeneration. However, if industrial firms begin to cogenerate and by so doing remove their demand from the utilities' system, residential customers could see their rates increase to cover the expenditures of a system with excess capacity and a deterioriated load curve. The overcapacity situation would be temporary; the utility would defer future expansion until its existing capacity is at the required level. In the interim, present ratepayers would be paying an "excess" amount for electricity so that future ratepayers could have less expensive electricity. Such discrimination has been a problem for the PUC in the case of allocating the costs of long-term construction problems.

Because of the lack of any trends towards cogeneration or toward large industrial firms removing their demand from the system, the issue was not explored with the PUC or the utilities; however, it could become important if such trends develop.

3. Inappropriate Issues

a. Rate for Selling Power. The amount of electric power available for sale is a function of the variability in the firm's individual demand from its cogeneration system. If and when by-product power becomes available, the firm would like to be able to receive benefits (income) from the electric generation. A firm's ability to negotiate a satisfactory price for the firm sale of excess by-product power could make this category of cogeneration more attractive. This issue is discussed in Section IV-A-1.

b. Guaranteed Long-Term Agreements. The least amount of interaction between the firm and the electric utility is required when there is no firm sale of electric power. Therefore, the importance of reconciling the difference in the planning horizons of the firm and the utility is minimized. (This issue is discussed in more detail in Section V-A-1). It is important for the utility to have some assurance of the future continuity of the industrial's reduced firm electric demand on the system and its increased standby demand. However, the utility has a mandate to supply electricity and therefore is not in a position to offer resistance based on the lack of assurance of long-term demand. Nevertheless, implementation of cogeneration systems that do not sell firm power could deteriorate the shape of the utility's load curve as the continuous load of large industry is removed, thus reducing the utility's peak demand in the short run and increasing the demand uncertainty in the future.

c. Steam Price. No steam transactions occur for this category of cogeneration.

d. PUC Regulation. Some observers of industrial cogeneration have questioned whether existing legislation would require the PUC to regulate an industrial firm selling electricity to an electric utility or to another firm. One interpretation of the California public utilities code implies the need for such regulation. However, the relatively small amount electricity sold compared with the amount utilized directly by the firm should make the prospect of direct regulation of the firm unlikely because of the cost involved to the PUC and the small impact on the utility's expenditure for purchased electricity.

e. Wheeling. The small amount of the electric power available for sale and its unreliability make it unlikely that the industrial cogenerator will be able to find an electric utility outside its service area or another firm in the same area willing to negotiate a sales agreement that would require wheeling of electricity over the transmission facilities of the local utility. Therefore, this issue should not be a barrier to firms considering this category of industrial cogeneration.

B. ENVIRONMENTAL ISSUES

1. Introduction and Description of the Best Available Control Technology (BACT) Provision of the New Source Review

Under the New Source Review rules, permits for further construction can be denied unless existing sources are "cleaned up." Since the sites visited in the initial phase of this study would fall under the category of modifications to existing stationary sources (as opposed to new stationary sources) only those appropriate provisions will be examined here.

The first step in this procedure is to examine the total emissions of the stationary source* after the modification to one of the units that make up the source. If the source will emit more than 15 pounds per hour or 150 pounds per day of nitrogen oxides, sulfur oxides, organic gases (hydrocarbons), or particulates, or 150 pounds per hour and 1500 pounds per day of carbon dioxide, the permit will be denied unless the applicant meets several criteria. These criteria are described in the best available control technology (BACT) provision. It should be noted that 15 pounds per hour is a restrictive limitation for a large industrial source which might cogenerate. Thus, if a firm already exceeds these limits, and does not increase its emissions further after the modification, it would still be required to meet the BACT provision. The BACT provision requires that the modification utilize the best available control technology and that the applicant meets one of the following four conditions:

*Stationary source is defined in Appendix G.

(1) The modification would not result in a net increase in emissions of any pollutant affected by this rule; or

(2) That best available control technology is being or is to be applied to all existing units of a stationary source, or

(3) That emissions from all of the existing units of the stationary source are controlled by use of technology that is at least as effective as that generally in use on similar stationary sources and that the cost of installing best available control technology on existing units is economically prohibitive and substantially exceeds the cost per unit mass of controlling emissions of each pollutant through all other control measures; or

(4) That the stationary source is a small business, that emissions from all existing units of the stationary source are controlled through application of the best technology that is economically reasonable to apply to that stationary source and that the cost of employing best available control technology is economically prohibitive.

The first condition might be met by this category of cogeneration because (by our definition) there is no net increase in emissions as a result of the modification. Thus, the only expense is that related to placing BACT on the equipment being modified. The other conditions become more important when there is an increase in emissions, as discussed in the next section. However, even firms meeting the first condition can incur additional expenses as a result of a modification made by the ARB when it adopted the NSR rules for the Bay Area in December 1977. This change from the rules previously adopted for the South Coast Air Quality Management District states that the permit will be denied unless the applicant:

> "... demonstrates that all facilities in the air basin which are owned or operated by the applicant are in compliance with all applicable district rules, regulations in order, and all applicable requirements of the state implementation plan approved or promulgated by the Federal Environmental Protection Agency."

This provision again shows that the NSR rules are perceived by the ARB as being an important means for reducing emissions from sources and that they are not just being applied to the modifications at existing units of a source. The ARB has indicated that this change will soon be incorporated in the NSR rules for the South Coast Air Quality Management District.

The second condition could prove to be quite expensive for the firm. Note that it applies to all units at the source and not just those that are modified. The South Coast Air Quality Management District has

interpreted this condition* to mean "that BACT must be applied to the total plant <u>or</u> to sufficient equipment so that there is no resultant net increase of air contaminants after the installation has been completed and has been put into operation." (Emphasis added.)

The third and fourth conditions encompass other factors such as "economically prohibitive" and "economically reasonable." These terms have neither been explicitly defined in the rules and regulations of the local agencies nor have they been interpreted. They are therefore a source of uncertainty for a firm applying for permit to construct.

2. Concerns About Best Available Control Technology

The ARB model NSR rules define BACT as

> "... the maximum degree of emission control for any air contaminant emitting equipment, taking into account technology which is known but <u>not necessarily in use</u>, provided that the air pollution control officer shall not interpret best available control technology to include a requirement which will result in the closing and elimination or inability to construct a lawful business which could be operated with the application of the best available control technology currently in use."** (Emphasis added.)

The Clean Air Act Amendments of 1971 state that a control technology must be adequately demonstrated before it is defined as BACT. EPA regulations defined "adequately demonstrated" to require that at least 10 different sites be found where the equipment has been installed and is operating. Use in the field is thus the EPA's sole economic criterion for the definition of BACT.

The ARB's definition cited above is even stricter than the EPA BACT definition since the technology can be known anywhere in the world; thus BACT for the control of nitrogen oxide in the boiler could be defined as ammonia injection, a technology applied in eight installations in Japan including boilers firing LPG and LNG, gas-fired annealing furnaces, an iron ore sintering plant, and several fuel oil boilers.*** The use of undemonstrated technology presents problems for evaluating the efficiency and reliability of future emissions reductions because empirical data are not available. This problem is exacerbated by the requirement of an air quality impact analysis (discussed in Section IV-B).

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*R. MacKnight, South Coast Air Quality Management District, personal communication, December 20, 1977.

**Based on discussions with the Air Resources Board, it appears that the concept of "closing and elimination" of a firm is the definition of "economically prohibitive." However, it should be clear that conditions causing one person to decide to close and eliminate a business could have less influence in another person's decision.

***<u>Energy Daily</u>, p. 2, July 20, 1978.

Despite the strictness of the ARB definition of BACT, there is still confusion as to what BACT really means. In an attempt to define BACT for various industrial processes, the ARB formed a joint ARB/APCD BACT committee to establish a list of BACT with the ARB serving as the statewide clearing house. Although a preliminary list was developed, the ARB appears to have stopped further development. Jan Bush, the Air Pollution Control Officer for Ventura County, requested in a letter dated Sept. 10, 1977, that the ARB reestablish the joint committee. According to the San Diego Air Pollution Control District, the ARB never responded to this request. This leaves the APCDs and California industry without a consistent or predictable list of the applicable BACT. Thus the local APCDs are open to review by the ARB for not applying the New Source Review correctly with respect to BACT. Because of the work being done by the EPA and the pollution control industry, BACT will always be advancing. This dynamic nature of BACT adds to the uncertainty over the ruling on a firm's application for authority to construct under the NSR rules.

A list of BACT would be helpful from the firm's standpoint. However, even a list might not solve the firm's problems for there is a fourth definition of BACT: that which appears in the Federal Regulations on the prevention of significant deterioration (PSD) and which the EPA has indicated might be applied to the NSR rules in the future. The PSD definition for BACT requires a case-by-case determination. This determination would include considerations of energy, environmental and economical factors. Although this definition might be useful for promoting cogeneration activities, it might also lead to greater uncertainty in the outcome of each firm's NSR applications.

The San Diego Air Pollution Control District provided a list of eight other issues they consider as unresolved with respect to applying BACT. These are:

(1) Common definition of BACT -- A common definition of BACT for use in NSR rules is desirable. Is it reasonable to assume that the NSR rules of all participating districts can be amended to include a common BACT definition?

(2) Different BACT in different areas -- Can BACT be different in different areas (e.g., rural vs. urban) within the same district?

(3) Standing committee for unusual BACT decisions -- Should a standing committee be formed to provide advice to APCDs in unusual circumstances? If so, then at whose initiative should the committee be convened?

(4) Other environmental effects/indirect emissions -- Are other areas of environmental concern to be involved in determination of BACT? (e.g., solid waste disposal and water quality control associated with air pollution control equipment). Should emissions produced by the power company in generating the electricity required to run the control equipment be considered in determining BACT?

(5) Existing equipment/additional increments of control -- In cases where BACT must be applied to existing equipment, is it justifiable to require new control equipment for small increments of reductions and emissions? If not, then what is the definition of "small increments"?

(6) Which pollutants are subject to BACT? -- When a source emits more than one pollutant, should BACT be required for all pollutants or only for the one(s) causing the source to become subject to NSR?

(7) Task force product - guideline vs. list -- What should be the output of the task force? Should it be a list of BACT as it is seen today, or should it be a set of decision guidelines to be applied by the APCD in making a decision on a case-by-case basis?

(8) Economics -- To what extent should cost enter into a decision regarding BACT? When is the cost of installing BACT to be considered economically prohibitive?

3. Application to Industrial Cogeneration

The industrial firms see the BACT provision as a hardship since it penalizes them for installing an energy conservation measure. They question why they should pay for more environmental control equipment when in fact they are helping to mitigate the total emissions because of their reduced electrical generating demands on the local utility. When industrial firms see unresolved issues related to implementing the BACT provision they are even more cautious about implementing energy conservation measures such as cogeneration.

The ARB and the APCDs are concerned with a very different problem - achieving clean air. The BACT provision is seen as a very useful tool for cleaning up existing air basins. However, the reduced net emissions claimed by firms as a result of the reduced electrical generation by the local utility is not relevant from the regulators' standpoint for the following reasons: First, the reduction in electric generation might not occur in the air basin in which the industrial firm is located. Second, even if a powerplant located in the air basin could be identified as the one where reduced generation takes place, the decreased emissions of pollutants such as particulates or sulfur oxides at the powerplant might not benefit the area near the industrial firm. These two pollutants are usually considered site specific, unlike reactive hydrocarbons which can affect the entire air basin.

One would like to be able to ask if industrial cogeneration is properly evaluated under BACT. That is, are the total benefits of applying BACT to industrial cogeneration greater than its total costs?*

*Economic efficiency would be indicated if the marginal benefits of applying BACT equal the marginal costs.

The answer to such a question is elusive because of the disagreement not only over the definition of BACT but also over the definition of costs and benefits. To the environmental regulators, the existing emissions are very costly and reductions at the site are benefits. To the firm, cleaning up its source (and as noted above, all its sources in the air basin) is the cost and the major benefit is energy conservation.

The discussion of BACT in this section assumes that there is no net increase in emissions with the implementation of cogeneration. Air Quality Impact Analysis, discussed in Section IV-B, is applicable to Category A cogeneration systems if there is a net increase in emissions.

C. ECONOMIC CONSIDERATIONS

The life-cycle cost comparison of the cogeneration system and the base system reveals whether or not, on a cost basis alone, the cogeneration system saves money for the industrial firm in the form of reduced costs. Receipts from the sale of any excess by-product electricity available from the cogeneration system are not included in this comparison. Thus, 11 of the 12 industrial sites and 13 of the 14 cogeneration systems can be evaluated considering industrial ownership with no firm power sales.*

The life-cycle cost comparisons for the base system and cogeneration system at each applicable industrial site are presented in Table 3-2. Eight of the sites had cogeneration systems with a lower life-cycle cost than the base system currently in operation at the plant.** The three exceptions are California Paperboard, Kaiser Steel, and Kelco; California Paperboard and Kelco each have another alternative available to purchase steam which will be discussed later. Kaiser Steel is the only exception without an alternative. However, it should be noted that the extremely high capital cost*** of $\$63 \times 10^6$ is probably due at least in part to Kaiser's unique environmental problems. Nevertheless, the life-cycle cost for the cogeneration system is only about 2.75% higher than for the base system. Thus, under the assumptions reflecting capital investments and electricity, O&M and fuel costs described in Appendix J, eight of the 11 industrial sites having the ownership option open to them could reduce energy costs by implementing cogeneration with no firm sales of power.

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*Husky Oil was the only site where an industry-owned cogeneration system was not discussed or even considered.

**Spreckels Sugar currently has a cogeneration system and for this site the base system was a hypothetical non-cogeneration system.

***Under the same assumptions used to estimate capital cost for all the other cogeneration systems, Kaiser's capital cost would be only $\$29.7 \times 10^6$, less than half the amount indicated in the site report.

Table 3-2. Life-Cycle Cost Comparisons: Industrial Ownership Without Firm Sales of Power

Industrial Firm	Life-Cycle Cost, 10^6 dollars: Base System	Life-Cycle Cost, 10^6 dollars: Cogeneration System
California Paperboard Corp.(1)	27.6(2)	34.5
California Portland Cement Co.	46.7	29.6(2)
Exxon Co., U.S.A.	156.4	66.6(2)
Hunt-Wesson Foods, Inc.-canning season(1)(3)	40.5(2)	79.6
Hunt-Wesson Foods, Inc.-all year, alt.1(4)	48.6	44.9(2)
Hunt-Wesson Foods, Inc.-all year, alt.2(1)(5)	48.6(2)	121.6
Kaiser Steel Corp.	199.1(2)	204.6
Kelco Co.(1)	57.0	75.5
Owens-Illinois, Inc.	40.5	31.4(2)
Simpson Paper Co.(1)	121.9	23.1(2)
Simpson Timber Co.	29.2	28.3(2)
Spreckels Sugar Co.	63.4	51.6(2)
Union Oil Co.	186.7	70.5(2)

(1) The option of firm sales of power for these cases is analyzed in Section IV.

(2) Most attractive system on a cost basis alone.

(3) Cogeneration system sized to meet canning season steam requirement and operates only during canning season.

(4) Cogeneration system sized to meet off-season steam requirement and operates all year.

(5) Cogeneration system sized to meet canning season steam requirement and operates all year, dumping steam during off-season.

Table 3-3 presents the incremental internal rate of return for each site evaluated for Category A. Note that for each site that has a cogeneration life-cycle cost less than that for the base system, the calculated internal rate of return is greater than the required rate of return.

Table 3-4 compares life-cycle costs for the base system and the cogeneration system for the currently allowed 10% investment tax credit and two investment incentives: a 20% investment tax credit and 6% interest loan (100% financing).

As expected, the larger the capital investment, the greater the impact of both the 20% investment tax credit and the 6% loan. Smaller projects, like that of Hunt-Wesson, sized to meet the off-season load, and of Simpson Timber, involving capital investments of less than one million dollars, are not significantly affected. Thus, both forms of incentive will encourage and favor large cogeneration projects over small ones.

D. CONCLUSIONS AND RECOMMENDATIONS

1. Institutional

Category A is the simplest form of industrial cogeneration to implement from a nontechnical perspective. There appear to be few policy problems. One necessary action is that the utilities justify their determination of standby rates for cogeneration. This rate should compensate the utility for maintaining the necessary capacity. The utility should not overcharge cogenerators who might require only a fraction of their aggregated capacity at any given time. In addition, final action on the National Energy Act and on the resolution of the rate design for each utility is important for providing a more certain decision environment.

Category A makes the smallest contribution to energy conservation, the smallest reduction of future capital expenditures, and represents a financial savings only to the firm, leading to either a higher return to its stockholders, lower prices to its customers or a combination of both. Therefore, available market mechanisms should be adequate to encourage this type of cogeneration once the actions identified above are completed. The PUC has already initiated discussions among the utilities to establish fair standby rates for cogenerators.

One remaining question is whether policies directed toward encouraging firms not to consider this scheme are appropriate because of the relatively small contribution it makes to energy conservation and reduced capital expenditures. Once investments are made by a firm, 15-20 years could pass before a new cogeneration system that is more energy and cost efficient is considered again (Reference 10, page 342). Such disincentive policies might be important if delays are anticipated in developing the proper decision environment for alternative cogeneration systems. However, these policies should be directed only toward those firms having steam loads compatible with cogeneration systems which have firm sales

Table 3-3. Calculated Incremental Internal Rate of Return: Industrial Ownership Without Firm Sales of Power

Industrial Firm	Incremental Internal Rate of Return*, %	Required Rate of Return (After Tax), %
California Paperboard Corp.	<0	12.5
California Portland Cement Co.	23.3	10.0
Exxon Co., U.S.A.	>40	12.5
Hunt-Wesson Foods, Inc. - canning season	<0	10
Hunt-Wesson Foods, Inc. - all year, Alt. 1	>40	10
Hunt-Wesson Foods, Inc. - all year, Alt. 2	<0	10
Kaiser Steel Corp.	<0	15
Kelco Co.	<0	15
Owens-Illinois, Inc.	17.3	12
Simpson Paper Co.	>40	12
Simpson Timber Co.	>40	12
Spreckels Sugar Co.	>40	10
Union Oil Co.	>40	10

*Additional power purchased at base system rate.

Table 3-4. Effects of Two Financial Incentives: Industrial Ownership Without Firm Sales of Power

Industrial Firm	Capital Investment, 10^6 dollars	Life-Cycle Cost, 10^6 dollars			
				Financial Incentive	
		Base System	Current 10% Investment Tax Credit	20% Investment Tax Credit	6% Low Interest Loan (100% Financing)
California Paperboard Corp.	3.7	27.6	34.5	33.8	32.2
California Portland Cement Co.	9.1	46.7	29.6	27.7	25.6
Exxon Co., U.S.A.	9.4	156.4	66.6	56.8	51.2
Hunt-Wesson Foods, Inc. - canning season	13.7	40.5	79.6	76.9	73.7
Hunt-Wesson Foods, Inc. - all year, Alt. 1*	0.3	48.6	44.9	44.9	44.8
Hunt-Wesson Foods, Inc. - all year, Alt. 2	13.7	48.6	121.6	118.9	115.7
Kaiser Steel Corp.	63.0	199.1	204.6	192.0	154.5
Kelco Co.	8.2	57.0	75.5	73.9	69.0
Owens-Illinois, Inc.	3.7	40.5	31.4	30.7	29.2
Simpson Paper Co.	8.1	121.9	23.1	21.5	18.3
Simpson Timber Co.	0.14	29.2	28.3	28.2	28.2
Spreckels Sugar Co.	---	---	---	**	**
Union Oil Co.	15.4	186.7	70.5	67.4	63.8

*Cogeneration system sized to meet the off-season steam requirement and operates all year.
**Financial incentives were not evaluated for Spreckels Sugar because they already have cogeneration installed.

of excess power or are utility owned. This selectivity requirement probably would make any policy implementation cumbersome and expensive.

2. Environmental

What can be done to help a firm implement industrial cogeneration and still keep the intent of the BACT provision? Several initiatives are suggested here for future study.

First, the ARB should reestablish the joint BACT committee to establish a set of guidelines for determining BACT and deal with the eight indicated issue areas. In addition, the joint committee should work toward developing a BACT list and establish a procedure for evaluating the status of the BACT list so that a firm would know how long the existing list will be current state of knowledge. If a case-by-case determination is held to apply to BACT, the joint committee should then be authorized to develop a list of operational guidelines for evaluating the cases.

The joint committee should be expanded to be a standing committee with staff and resources and should include representation from industrial and environmental interest groups.

Second, the ARB should consider a more flexible definition of BACT which recognizes its energy conservation benefits, e.g., the relevant BACT must be adequately demonstrated at several similar plants before it can be applied to an industrial cogeneration modification.

Third, the ARB and the APCDs should consider the benefits of reduced emissions from a utility powerplant resulting from industrial cogeneration. In other words, because cogeneration itself is a form of control technology for the utility, the industrial firm should be given credit for expenditure for the modification. An emissions credit in lb per hour could be established for each kilowatt-hour of utility energy displaced by industrial cogeneration. The credit need not be the full value, but at least some percentage of this should be applicable.* Formalizing these credits would acknowledge the total social contribution of industrial cogeneration and could provide the motivation for increased industrial participation. These initiatives should be explored and analyzed; they point to areas where compromise is possible without diminishing the intent of the New Source Review rules.

*The percentage for each pollutant should be based on environmental grounds similar to those implied under the air quality impact analysis. These air basin benefits and cross-air basin benefits are discussed in the next section.

SECTION IV

ANALYSIS OF CATEGORY B: INDUSTRIAL OWNERSHIP WITH FIRM SALES OF POWER

In this institutional setting, the industrial firm sells cogenerated electricity that meets specific contractual conditions related to the reliability and availability of the power. Because of these contractual stipulations, the firm can either meet all of its internal electrical requirements and commit to the utility only that capacity over and above its own demand, or it can commit all of its capacity to the utility and continue to buy electricity from the utility. The difference between the price paid by the firm for electricity and the price offered by the utility is an important consideration in the determination of the alternative chosen. If the price offered by the utility is less than the price paid by the firm, the firm can reduce its net expenditures by first offsetting its electrical demand. However, other factors, such as the price of standby power, could reduce this price differential. Topping cycles are usually associated with this form of industrial cogeneration.

To clarify the discussion of the institutional issues, it is assumed that the firm commits all of its capacity to the local utility and continues to purchase all of its electricity from the firm. The advantage for the firm is the increased reliability of the purchased electricity in comparison to the electricity produced by its own cogeneration plant. The advantages for the utility company include the continuity of both the supply of electricity and the demand for power.

A. INSTITUTIONAL ISSUES

The relevant issues appear to be the selling price for electricity delivered to the utility's distribution system by the cogenerator, the nature of the long term agreement, and the determination of the regulatory status of the cogenerator. The subject of wheeling, the possibility of changes in natural gas priorities, and changing electric rate design are also important.

Category B, the most difficult of the three categories to implement, provides the greatest savings in energy and capital expenditures and involves the most interaction between the utility, the firm, and the Public Utilities Commission.

1. Primary Issues

a. <u>Selling Price for Excess Electricity</u>. The price offered for electricity produced by industrial cogeneration is important in determining the economic benefits of implementing cogeneration and in determining whether or not the firm will sell excess electricity continually or intermittently. The price will be determined through

negotiations between the firm and the electric utility company. In addition, the Public Utilities Commission (PUC) is playing an influential role in requiring utilities to establish tariffs. (See Appendix B.)

The Industrial Firm's Viewpoint

Several firms viewed pricing as a key issue. Exxon Company, U.S.A. felt that the current price of 1.4¢/kW-hr offered by the utility (Pacific Gas and Electric Company) for by-product power was inadequate since it barely covered fuel costs. California Portland Cement Company agreed with this view although it is serviced by Southern California Edison Company (SCE).

Three companies expressed views on whether or not favorable prices would be obtained. Hunt-Wesson Foods, Inc., felt that the utility company would not be willing to pay a reasonable price for (industrially generated) power. Simpson Paper Company, however, was under the impression that the present attitude of their utility company (PG&E) was more receptive.

Utilities might have to begin to offer higher prices if they are to retain their large customers. Otherwise, the large customers could remove their demand from the system and supply their own needs through cogeneration, leading to a deterioration in the utility's load curve.

The Electric Utility Company's Viewpoint

The utilities have made some dramatic changes in their views on the purchase of energy from industrial firms. In the past this activity was frowned upon and only as a result of capacity shortages caused by the recent drought did some of the utilities begin to reconsider purchase of industrially generated power. However, even in these cases, industrially generated power was considered to be inferior to utility generated power. A PG&E representative noted that "industrial operating practices are different in most cases and in many ways incompatible with good utility operating practices." (Reference 15, pg. 35.)

Changing circumstances have forced the utilities to reconsider the value of the capacity and the energy produced by industrial cogeneration. For each utility, this value will be different and within each utility system the value of energy varies on a daily, seasonal, and annual basis. On a daily basis, the utility goes from periods of peak demand, where more expensive power plants must be operated, to mid-peak and off-peak periods where less expensive base load power provides the major portion of the supply. Accordingly, the Southern California Edison Company has suggested that the price it will pay will vary depending on the time of day the electricity is delivered to the system. On a seasonal basis, the availability of inexpensive hydro-power can become an important factor in determining the value of industrially generated power. Thus, PG&E would like to retain the ability to reject industrial power if less expensive power is available. In addition, peak periods vary with the seasons. On an annual basis, the relationship between the utility's capacity and demand are changing, especially as additional capacity is

delayed in coming on-line. For example, in the first quarter of 1978, the number of kW-hrs of electricity sold by the major electric utilities in California was 5.8% less than the comparable period of 1977. (Reference 16). Thus, it is reasonable that the price the utility pays should fluctuate over time. (A more detailed description of the differences between the utilities appears in Appendix C.) As noted above, the Public Utilities Commission has requested the electric utilities to submit guidelines covering the prices and conditions for the purchase of energy from industry-owned cogeneration facilities.

From the industrial firm's point of view, fluctuating value may be of concern. In essence, they are evaluating the return on an investment for a new "product line." They would like to know with a degree of certainty the revenues that can be expected as a result of the investment. Although a time-dependent rate incorporated into the original contract would probably be acceptable, the possibility of going without any revenue for a period of time might be too risky.

Again, from the utility company's point of view, agreements that do not allow for price fluctuation due to external conditions could force them to buy overpriced electricity in comparison to other available sources. Such a situation would be reflected in higher costs to the utility's customers. However, at the same time, the utility needs to be concerned with keeping its established industrial customers. Industrial customers are highly valued by the utilities because their demands are usually continuous and large in comparison to residential customers. Historically, this has been expressed as a reduced price for industrial customers. Therefore, the potential loss of such a customer needs to be evaluated by the utility. In the long term, the utility will be able to adjust for such losses. In the short term, which is specified by the length of the rate hearing process, the result could be a loss of net revenue for the utility. The utilities might minimize that loss by offering more attractive rates to industrial customers for the purchase of all their cogenerated electricity.

The purpose of this discussion is to show the difficulties that must be overcome before the firm and the utility can enter into an agreement over the price of cogenerated electricity. All of the prices suggested by the utilities fall below the rate at which they, the utilities, sell electricity. Therefore, a firm would prefer to offset purchased power with cogenerated power instead of selling directly to the utility because it would be a greater benefit (a negative cost). This evaluation is adjusted by the necessary standby charges described previously. Even as the ratio of electricity cogenerated to electricity demanded increases, the firm can maximize the return on its cogeneration investment by first offsetting its electrical demand and then selling the excess electricity.

These conclusions rest on the assumption that cogenerated electricity is priced as some percentage of the utility's total average cost or average cost of oil and gas generating facilities. The percentage reduction represents the administrative charges incurred by the utility. However, it is a well known fact that "the average price of energy has

now fallen well below the still rising replacement cost of energy supplies." (Reference 17, pg. 112.) Should cogenerated electricity be evaluated as a percentage of the replacement costs? If so, and assuming no radical change in the utility's rate design, the economic incentive for utility ownership could be sufficient.

The situation described, with firms receiving a higher price for the sale of electricity than for the purchase of electricity, could raise questions by the other ratepayers. This would especially be true if the firm achieves a very high rate of return on its cogeneration investment. Ratepayers are accustomed to utilities earning a 8-10% return on investment Realizing this concern, industrial firms will want assurance that they are not going to be regulated by either the Public Utilities Commission or the Federal Energy Regulatory Commission.

b. Regulation. When a firm owning a cogeneration system sells electricity either to another firm or to an electric utility company it could conceivably come under the definition of an "electric corporation" found in the Public Utilities Act (Paragraph 218):

> "Electrical corporation includes every corporation or person owning, controlling, operating or managing any electrical plant for compensation within the State, except where electricity is generated on or distributed by the producer through private property alone, solely for his own use or the use of his tenants and not for sale to others."

When such an electrical corporation performs a service for the public it is a "public utility" (as defined in Paragraph 216) and subject to the Public Utilities Act. (See Appendix C for a description of a public utility.) The issue is whether or not an industrially owned cogeneration facility should be regulated.

The Industrial Firm's Viewpoint

The uncertainty created by the language of the Public Utilities Act has been the cause of much concern on the part of several firms. Exxon Company, U.S.A. stated that it has no interest in becoming an electrical public utility. California Portland Cement Co. called the reaction of the PUC to the sale of electric power outside of its plant their biggest uncertainty. There appears to be little, if any, willingness on the part of industrial firms to allow their practices to come under the direct jurisdiction of the PUC.

The Public Utilities Commission's Viewpoint

Before looking at the recent activities by the PUC on this issue, it is appropriate to reexamine the case of Richfield Oil Corporation vs. Public Utilities Commission (Reference 18). In this case the PUC had found that Richfield Oil Corporation was a public utility as a result of its 1959 contract with SCE to provide natural gas for a period of 25 years. To do this, Richfield had to build a pipeline. Southern

Counties Gas Company, the certified public utility in the area, filed a complaint with the PUC based on Section 1001 of the California Public Utilities Code. That section stipulates that a certificate of public convenience and necessity must be acquired before a public utility can build a pipeline. The PUC agreed that Richfield was a public utility and ordered that a certificate of convenience was required.

Richfield petitioned the California Supreme Court. The Court held that the commission's order should be annulled. The decision hinged on the definition of dedication. A law review article on the case, noted that:

> "Dedication had originally been incorporated into the law to satisfy a constitutional question but that question is no longer an issue. However, since the codification of the original Public Utilities Act in 1911 the legislature has repeatedly enacted the pertinent code Section of 207 and 216, defining 'public' and 'public utility' in substantially the same form, saying nothing of dedication even in light of judicial interpretations requiring dedication since 1912. This strongly suggests legislative intent in accord with the case holdings." (Reference 19, pg. 328.)

The article goes on to note that, under the California Code of Civil Procedure, a court cannot "write into a statute, by implication, express limitation which the legislature itself has not seen fit to include in the statute." (Reference 19, pg. 331.) This, however, appears to have been done in the case of dedication. The article concludes:

> "If the legislature would define dedication with respect to becoming a public utility, that meaning would be binding in the courts, and corporations desiring not to become regulated utilities would have a more concrete basis on which to plan their business activities."

Without such a definition each case must be considered separately. As noted in a PUC memorandum by William N. Foley, Assistant General Counsel of the PUC:

> "Whether a privately-owned cogenerating industrial company which sells electricity to a public-owned or privately-owned utility is itself a public utility will depend on the facts and details of the arrangement between the two parties. A firm which operates only one cogeneration facility in the state might be held not to be a public utility, particularly if its agreement with the purchasing utility is for the sale of surplus power on an infrequent basis at a price to be determined separately for each sale. On the other hand, if the company has two or more cogeneration facilities in the state and sells power on a firm basis, it might well be

held to be a public utility. This might be true even if the cogenerator has only one powerplant, but agrees to sell power on a firm basis at a fixed price for a substantial period of time. If the company operates several cogeneration facilities and sells power to more than one utility it could be held to be a public utility. The legal results will depend on the operational facts and the details of the sales contract involved in each individual case."*

Mr. Foley concludes that legislation clarifying the utility status of cogeneration is required.

The PUC is aware of the concerns over legislation by California firms considering cogeneration. In its staff report on cogeneration the Utilities Division states that:

"Industry has shown resistance to cogeneration projects for fear it might be considered a public utility and subject to PUC jurisdiction." (Reference 5.)

The staff of the Utilities Division of the PUC goes on to say that it

"does not regard the customer who generates all or a portion of electricity for his own use and sells surplus energy to a utility as a public utility and subject to Commission regulation." (Reference 6.)

The PUC and the state legislature are looking into this matter. However, the PUC has shown some reluctance due to a concern that legislation might be premature and therefore might foreclose socially beneficial implementation of cogeneration systems. The PUC would prefer to provide firms with an opportunity to experiment with many cogeneration arrangements before any legislation is produced. The only problem is that without the legislation, the development of cogeneration might be significantly inhibited in its development and not reach its full economic potential.

Through its review of all special contracts, the PUC has some indirect control over firms that sell electricity. How far the PUC will need to go to establish that the electric utility company is paying a fair and equitable price for the electricity is still an open question. Therefore, even if the PUC or the state legislature decides not to regulate cogenerators, the industrial firms might still be reluctant to cogenerate because of the required review of their operating and financial records.

*Memo to PUC Commissioner Claire Dedrick, from William N. Foley, March 3, 1978.

Summary of the Issue

Two points in the PUC Utilities Division staff statement should be emphasized. First, the regulation of firms that sell all of the cogenerated electricity to a utility is not addressed. Second, it is the view of only the PUC Utilities Division's staff. The PUC legal department, as noted, has indicated the need for a case-by-case analysis of whether or not the cogeneration facility is dedicated to the public use and is, therefore, subject to regulation by the PUC.

As a result, both the industrial firms and the electric utility companies expressed the need for legislation exempting cogeneration from being classified as a public utility. Mr. Gerald Decker of the Dow Chemical Company stated in his congressional testimony on cogeneration that:

> "The existing regulations which tend to prohibit electricity sales by private industrials are so complex that positive and specific exemptions from utility regulations are necessary to entice an industrial firm to even attempt an electric power sale." (Reference 20, pg. 334.)

The testimony was given with respect to those parts of the National Energy Act and related legislation on cogeneration. In the early legislation the Federal Power Act was to be amended to state that "provisions . . . shall not apply to a cogeneration facility."* This was amended so that the existing legislation states that "power procedures of over thirty megawatts may not be exempt from the Federal Power Act."

Thus, the issue of regulation is still unresolved and until it is, many firms will forego investments in cogeneration. Unfortunately, discussions of the regulation issues never seem to address a more fundamental question - regardless of all the legal precedents, are there justifiable reasons for regulating an industrial cogenerator? The answer is related to the special role assigned to the generation of electricity in the U.S. economy as a regulated industry. Is cogenerated electricity different? These questions which require an examination of the reasons for regulating electrical generation, are beyond the scope of this study.

c. Long Term Agreements. In addition to the price paid by the utility for firm cogenerated electricity, the utility and the cogenerator must also come to some understanding on the operating interface and on the length of the commitment by the two parties. Electric utilities are accustommed to a 5 to 10 year planning horizon and are reluctant to make investments that will not help them over this time period. Manufacturers are usually more accustommed to a shorter planning horizon in relation to decisions at individual plants. The required contractual arrangements must reflect these two concerns. The problems of negotiating such an arrangement are discussed in Section V-A-1-a.

*Reference 9, Section 107(c).

2. Secondary Issues

a. Rate Design. Changes in rate design can have two different effects. They can:

(1) Increase the rates for electricity and thus heighten the firm's willingness to consider cogeneration.

(2) Change the differential between the price paid by the firm for electricity and the price paid by the utility for cogenerated electricity. An increase in the difference will discourage the implementation of industrial cogeneration as discussed in this chapter.

The issues and views related to changes in rate design were examined in Section III-A-2-b.

b. Wheeling. Wheeling is the use of the transmission facilities of one system to transmit power of and for another system. Wheeling is also one of the most controversial subjects in the study of the electric utility industry. Although major electric utility companies will normally wheel power for one another, their relationship with the smaller municipal utilities has been less than cooperative in many cases (see Appendix F). The utilities' wheeling relationship with industry is almost nonexistent.

When does wheeling arise as a major issue? Wheeling is closely related to the issue of the selling price of excess electricity. If the selling price is sufficiently high, the issue of wheeling never arises.

If the price offered by the local utility is not considered high enough, the option to wheel that power from the industrial firm to a nonlocal utility or to another firm could help to keep the proper incentives for cogeneration without having the local utility pay what might be to them an excessive price.

The operational aspects of wheeling for a cogenerator could become difficult to manage for an electric utility. For example, what procedure should be followed by the utility transporting electricity if the cogenerator must shut down its generators for a short time period? Should power delivery at the other end of the transmission be stopped for the same period? Should payment be made for keeping the electric supply continuous? If so, what is a proper price for such a service?

The Industrial Firm Viewpoint

Three of the 12 firms surveyed considered the ability to wheel power as an essential part of their cogeneration scheme. For California Portland Cement, the ability to wheel power at a favorable cost over SCE lines from its Mojave plant to its Colton plant was a necessary factor for one system under consideration. The wheeling capability was

considered by California Portland Cement to be required in addition to receiving a favorable price from the utility for power sold to the grid. Kaiser Steel expressed a similar concern for having the capability to have electricity wheeled to an interested municipal utility. It is not clear how the situation might change if the municipal utility owned the cogeneration plant at the Kaiser Steel facility. In this case the wheeling would be done between utilities, a common and accepted practice in California.

Simpson Timber has requested that PG&E allow them to wheel power to other plants. Industrial wheeling, according to Simpson Timber, is a common practice in the Northwest.

The Electric Utility Company's Viewpoint

The utilities do not perceive wheeling as an issue. They feel that the same result can be achieved by two distinct operations: utility purchase of cogenerated power and the subsequent sale of that power. The issue of wheeling is raised as a means to ensure that the firms are offered a fair price. Because the utilities are confident that they will offer a fair price, they feel that this issue need not be raised.

The Public Utilities Commission's Viewpoint

The PUC agrees with the utilities, noting that even raising the issue could become a major deterrent to utilities' support of cogeneration. The PUC feels that its actions requiring the utilities to offer a fair price for cogenerated electricity will preclude the necessity for wheeling.

At the federal level, wheeling is still viewed as an important issue. In Section 241(b), Title II of the proposed H.R. 4018 - Public Utility Regulatory Policies Act - the Federal Energy Regulatory Commission (FERC) can, by order, direct an electric utility to:

"(A) establish physical connection of its transmission facilities with the facilities of any other electric utility or qualifying cogenerator, or

(B) (i) sell or deliver energy to or exchange energy with,
(ii) provide pooling for,
(iii) provide wheeling or otherwise transmit energy for, or
(iv) otherwise coordinate with, such utility or cogenerator."

The FERC cannot make such an order unless it determines that the consumer of an electric utility will receive benefits and that "no utility subject to such order or its customers will suffer economic hardship." (Section 241(a).) The section goes on to exclude from the paragraph, the transmission of electric energy to an "ultimate customer." This would apply to plant A wheeling to plant B over a utility's transmission or distribution system.

Even if this proposed legislation is passed, it could be a long time before the FERC determines how and when it will apply the law.

Summary of the Issue

Wheeling is a complex issue because of its close relationship to many other issues concerning electric utility regulation. Both industry and the U.S. Congress have indicated the possible need for wheeling. The PUC and the utilities in California do not perceive it as an issue. Wheeling, they believe, can be avoided by negotiating a fair price for cogenerated electricity. If the local utility does not need the cogenerated electricity or does not value it as highly as another utility, arrangements should be made between the utilities. For example, if San Diego Gas and Electric (SDG&E) wanted to purchase electricity from a firm in the Southern California Edison (SCE) service area, SDG&E would arrange to purchase electricity from SCE. SCE would then be able to offer a different, presumably higher, price to the firm and then in a separate agreement sell power to SDG&E.

c. Natural Gas Priorities and the National Energy Act. The issues related to the change in natural gas priorities and the National Energy Act are discussed in Sections III-A-2-a and III-A-1-b, respectively.

3. Inappropriate Issues

a. Standby Power Charge. A firm buying all its electricity from the utility does not require standby power. The standby power charge will, however, affect a firm's decision to supply firm power. Standby power issues are discussed in Section III-A-1-a.

b. Steam Sales. Category B does not involve steam transactions.

B. ENVIRONMENTAL ISSUES

1. Introduction and Description of the Air Quality Impact Analysis (AQIA)

The Best Available Control Technology (BACT) provision, discussed in Section III-B, is intended to prevent stationary sources from increasing their emissions by requiring the use of technologies that will at least maintain the status quo in emissions.* For sources with larger emissions, the New Source Review (NSR) rules require an Air Quality

*All of the sources subject to AQIA are necessarily subject to the BACT provision.

Impact Analysis (AQIA). The intent of the AQIA with respect to modifications to existing stationary sources* is to deny a permit to construct if the modification will result in a net increase in emissions that will interfere with the attainment or maintenance of ambient air quality standards. In other words, the AQIA focuses on net emission increases due to the modification, while the BACT provisions consider total emissions from the entire source. The net emission increase must be:

> "... greater than 25 pounds per hour or 250 pounds per day of nitrogen oxides, organic gases, or any air contaminant for which there is a state or national ambient air quality standard (except carbon monoxide, for which the limits are 250 pounds per hour and 2500 pounds per day)."

How, then, is the local Air Pollution Control Officer to determine that the emissions will not interfere with the attainment or maintenance of specific ambient air quality standards? The rule mentions only what should be considered in the analysis of the effect on air quality:

> "Such analysis shall consider the air contaminant emissions and air quality in the vicinity of the new source or modified source, within the air basin and within adjoining air basins..."

One of the key aspects of the ARB's model New Source Review rule is the concept of trade-offs or offsets to achieve emissions reduction. The basic idea is for the Air Pollution Control Officer to allow the net increase in emissions from the applicant's source to be offset, traded-off, with a reduction in emissions from another source. Thus, if Plant A will be increasing its emission by 100 pounds per hour because of cogeneration, a permit to construct would be granted if the plant could modify or eliminate another source such that the net emission of both sources did not interfere with the attainment of an ambient air quality standard.

A few clarifying remarks are necessary:

(1) The trade-off is by air contaminant. Thus, the net increase in nitrogen oxides cannot today be traded-off with a net reduction in sulfur oxide at another plant.

(2) The stationary source where the emission reduction occurs must be located in the same air basin as the increased emitter.

*Because the sites visited are considering cogeneration as a modification, only the corresponding provisions of the NSR rules are considered here.

(3) The trade-off must be real and the applicant must be able to demonstrate that the air basin will in fact experience a net decrease in emissions.*

(4) The rules have thus far been construed that the source where the reduction in emissions occurs must be under the same ownership as the increased emitter.

(5) Emissions reduction cannot be used in the trade-off if they are already required by law. Thus, the applicant cannot use the reduction in emissions due to the use of BACT at other units at the source because this would be required by law under the provisions of the NSR rules as discussed previously.

The latest version of the NSR rules adopted by the ARB (for the Bay Area Air Pollution Control District) includes the one additional constraint that to obtain a trade-off the "applicant must demonstrate that there will be a net decrease in the emissions of <u>all</u> air contaminants emitted..." (emphasis added). Thus, even if nitrogen oxides were the only pollutant for which there was a net increase in emissions over 25 pounds, the firm would still be required to find other sources, including its own, that could be modified to result in a net decrease in pollutants other than nitrogen oxides before it could apply for the trade-off consideration. This change from the original model NSR rules will presumably be incorporated in the South Coast Air Quality Management District and all other future NSR rules adopted by the California APCDs.

The NSR rule contains several criteria for granting exemptions from the AQIA. Three of the exemptions are pertinent to industrial cogeneration:

(1) The proposed stationary source modification will cause "demonstrable air quality benefits." ARB and EPA written concurrence is required prior to granting this exemption.

(2) The modification will utilize "unique and innovative control technology" resulting in a "significantly lower emission rate" than the "previously known best available control technology." EPA and ARB concurrence is required.

(3) The modification of the stationary source "represents a significant advance in the development of a technology that appears to offer extraordinary environmental or public health benefits or <u>other benefits</u> of overriding importance to the public health or <u>welfare</u>." (emphasis added) Here again, EPA and ARB concurrence is required.

*For example, if Plant B is presently emitting 75 pounds per hour of organic gases but it is authorized to emit 100 pounds per hour, the difference of 25 pounds per hour could not be traded off Plant A; only actual emissions can be traded off.

2. Concerns About Implementing the AQIA Provision

Discussions with the ARB and the local APCDs indicate that the AQIA provisions are intended to give the local Air Pollution Control Officer (APCO) a considerable degree of latitude in making determinations on permits to construct. The rule provides no algorithm for permit review. Specific factors to be considered are not indicated nor does the rule indicate the importance to be attached to various factors. Obviously, this allows the APCO to use his own discretion in arriving at a decision.* Thus, the application of the AQIA will be capable of change as conditions necessitate. The ARB felt that this dynamic characteristic was important for the APCO to judiciously apply the NSR rule. For the firm, however, this dynamic characteristic is fraught with arbitrariness and uncertainty.

The determination of the trade-off ratio** is probably the most political of all aspects of performing an AQIA. The ratio is used as a surrogate for modeling. If an accurate air quality model were available, the demonstrable air quality benefit could be shown analytically.*** Without such reliable models, the ratio is used, with certain caveats, to insure that more pollutants are removed than are added by the new units. The factors used in computing the ratio have not yet been established but, according to the ARB, include the type of pollutant, other nearby facilities, and the demography of the air basin. Note that site-specific pollutants, such as particulates, require trade-offs with sources near the new source in order to prevent one location in the air basin from benefitting at the expense of another. Because all of these divergent aspects must be incorporated into one ratio, it is unlikely that a single ratio can serve a whole air basin let alone an entire state. Thus, for example, resolution of the so-called Sohio case might not establish a precedent for administering trade-offs.

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*A firm can appeal an unfavorable decision. The ARB can intervene only if it finds that the rules are not being implemented correctly. In the case of the Bay Area APCD, discussed in the next chapter, the ARB never overruled the local APCD but instead found that the existing rules were inadequate and therefore adopted new rules for the District.

**A ratio of 1.2 to 1 means that for every pound of net emission increase of a pollutant, 1.2 pounds of that pollutant must be eliminated. There are in fact two ratios: a "safety factor" ratio which must be met daily and a "project benefit" ratio that is calculated on an annual basis.

***Discussions with the ARB and several APCDs indicated that even with a modeling capability, the equity problems involved in determining air quality benefits for an entire air basin could be very difficult to resolve.

The Sohio case refers to the first significant application of the trade-off concept in California. The project itself involves the construction of a marine terminal, 10 storage tanks, and pipeline segments that connect to existing lines to Midland, Texas. Alaskan crude oil would thus be delivered to the mid-West at a cost savings in comparison to going through the Panama Canal. To acquire its authority to construct, the Standard Oil Company of Ohio (Sohio) entered into negotiations with the Southern California Edison Company (SCE) that would have Sohio buy $78 million worth of pollution control equipment for SCE to offset the net increase in emissions that would result from the terminal operations. Negotiations were described as "not easy." For example, some of the issues that needed resolution were: (1) Who is responsible for continuing operations and maintenance? (2) What if the control equipment fails; who is responsible for its repair? and (3) Who pays for cost overruns? Although the Sohio case is referred to as an application of the NSR rules, the case falls under the third exemption discussed above. One problem area is the estimates of the reliability and efficiency of the BACT - scrubbers - which is to be applied at the SCE plant. Such data are necessary to compute the trade-offs; thus, the use of the ARB definition of BACT (see Section III-B) presents a "Catch 22" -- to obtain the operating data one needs to demonstrate the technology, but in order to demonstrate the technology one needs the operating data to obtain the required permits.

3. Application to Industrial Cogeneration

The concept of a pollution trade-off appears to be designed for industrial cogeneration -- the industrial firm offsets the utility's electric capacity (and emissions) by generating electricity on-site. Thus, while the industrial firm burns more fuel, the utility benefits since it, theoretically, can reduce its own fuel consumption.

The key word above is "theoretically." Since the local APCDs consider only actual trade-offs, the firm needs to prove that the utility would be permanently reducing its own electric generation capacity. For site-specific pollutants, the utility's powerplant must therefore be nearby. However, the utility may prefer cutting back on its purchased power agreements rather than reducing generation at a baseload powerplant in the local area.

The question which remains is whether the NSR rules are constructed so that they do not recognize the benefits of industrial cogeneration.* The industrial firms point to the net decrease in emissions after the implementation of industrial cogeneration, while the air pollution regulators note that emissions are not easily aggregated -- reductions in one air basin may not necessarily help another air basin. Even

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*The California Paperboard Corporation's joint project with the City of Santa Clara is discussed in Section V as an example of a case where the exemption clauses of the NSR rules relating to "innovative technology" were tested. For the present section, only the rule's nonexclusionary clauses are discussed.

within an air basin as diverse as the Bay Area, some zones have carbon monoxide problems and others have sulfur oxides problems. Thus, within this basin, a cogeneration plant that increases carbon monoxide in one community and reduces carbon monoxide in another harms the former and is ineffective in alleviating the (sulfur oxides) problems of the latter. Regulators do not regard this as helpful in meeting ambient air standards. As far as its legal mandate goes, industrial cogeneration is not very special.

C. ECONOMIC CONSIDERATIONS

The net present cost is defined as the reduction to the cogeneration system life-cycle cost due to receipts from the sale of by-product power. A comparison of the net present costs for the case of industry ownership of the cogeneration system with firm power sales, results in many alternatives that are more attractive than the corresponding base system. The analysis considers the cases where (a) only excess by-product power is sold, and (b) all cogenerated power is sold.

1. Sale of Excess By-Product Power

Five cogeneration system alternatives are available to four of the surveyed industrial sites where the sale of excess by-product power is feasible based on annual consumption requirements and calculated cogeneration system output. When the price of this excess power is assumed to be equal to the purchase price of electricity the industrial firm currently pays the utility, the upper bound on the benefit to the firm from the sale of excess power is assumed to be established. Not surprisingly, the net present cost is lower than the base system life-cycle cost in each instance (Table 4-1).

When the price of excess power is assumed to be 14 mills/kW-h, Pacific Gas & Electric Company's standard offer to industrial firms with electric power for sale, a possible lower bound on the benefit to the firm is established. Surprisingly, for four of the five cogeneration systems with excess electricity, this price also yields a lower net present cost than the base system life-cycle cost. The only exception is the Hunt-Wesson canning season alternative. In view of the fact that the other Hunt-Wesson alternative did have a lower net present cost than the base system, it is surprising that all four industrial firms can have an economic cogeneration system even when the price for excess by-product power is set at what could be considered a lower bound. It should be noted, however, that the difference between the base system life-cycle cost and the net present cost for California Paperboard is almost negligible and the difference for Hunt-Wesson and Kelco is not significant, implying that hidden factors could favor the base system over the cogeneration system. The primary reason for such a large difference for Simpson Paper is a change in fuel type between the base system and the cogeneration system - the former uses natural gas while the latter uses considerably cheaper hog fuel.

Table 4-1. Net Present Cost Comparison: Industrial Ownership With Firm Sales of Excess Power

Industrial Firm	Excess Power Generated, 10^6 kW-h/yr	Base System Life-Cycle Cost, 10^6 dollars	Net Present Cost, 10^6 dollars		Break-Even Price[5] for Excess Power, ¢/kW-h
			(3)	(4)	
California Paperboard Corp.	38.3	27.6	23.4[1]	27.5[2]	1.4
Hunt-Wesson Foods, Inc. - canning season[6]	150.2	40.5[2]	23.5[1]	46.9	1.7
Hunt-Wesson Foods, Inc. - all year, Alt. 2[7]	362.3	48.6	(13.7[1])	42.7[2]	1.3
Kelco Co.	135.2	57.0	23.2[1]	54.8[2]	1.2
Simpson Paper Co.	46.6	121.9	(2.7[1])	14.3[2]	<0

(1) Most attractive system when power sold at base system rate.

(2) Most attractive system when power sold at 14 mills/kW-h.

(3) Excess power sold at base system rate.

(4) Excess power sold at 14 mills/kW-h.

(5) Required price for excess power which will equate cogeneration system cost with base system cost.

(6) Cogeneration system sized to meet canning season steam requirement and operates only during canning season.

(7) Cogeneration system sized to meet canning season steam requirement and operates all year, dumping steam during off-season.

Finally, a break-even price for the sale of excess by-product electricity was calculated for each applicable system (Table 4-1). The break-even price is that price which yields a net present cost for the cogeneration system that is equal to the life-cycle cost for the base system it would replace. In general, the break-even price for excess by-product electricity reflects the surprising results just noted.

Since the issue of a favorable price for excess by-product electricity was considered an important factor by half the firms surveyed, these results are even more surprising. On the surface, it would appear that this issue is not as important as the firms perceive it to be. Only four had excess by-product electricity available, of the 12 industrial firms studied, and one of those four firms, Simpson Paper, has a cogeneration system alternative that is more economical on a cost basis alone, independent of whether or not excess by-product electricity is sold.

Underlying factors may contribute to this unexpected result, although in some of the more attractive situations they cannot explain it entirely. Presumably, a cogeneration system is preferred when its life-cycle cost is less than the base system life-cycle cost. However, when the life-cycle cost of the base system is greater than the net present cost of the cogeneration system but less than the life-cycle cost of the cogeneration system, there may be additional hidden costs associated with, say, contract negotiations or interfacing with the utility, that more than offset the benefit to the firm. Such a situation is similar to a firm's adding a new product line (in this case electricity), and many of the industrial firms interviewed were not interested in product diversification.

2. Sale of All Cogenerated Power

A second option available under Category B is for all cogenerated power to be sold to the utility while the industrial firm continues to purchase its required power from the utility at the base system rate. Table 4-2 presents the life-cycle cost and net present cost comparisons when cogenerated electricity is sold to the utility at 19.5 mills/kW-h, a price based on the SCE "Alternate B" plan (see Appendix D) in which the utility requires certain minimum guarantees for the power supply and agrees to pay an amount that allows for a capacity credit, an energy credit and a small operations and maintenance credit. For this case, two cogeneration systems, Hunt-Wesson, sized to match the off-season steam requirements, and Simpson Paper, have life-cycle costs that are lower than the base system life-cycle cost. All the cogeneration systems, with the exception of Kaiser Steel's, have net present costs that are lower than the base system life-cycle cost. Thus, while this option results in generally higher life-cycle costs than those in which the industrial firm offsets some or all of its electrical requirements with cogenerated power, it nevertheless is economically viable. It is not the most attractive alternative for cogeneration from the industrial firm's point of view, but it is competitive. The major factors that may detract from this alternative are the additional costs associated with contract negotiations and interfacing with the utility.

Table 4-2. Life-Cycle Cost Comparisons: Industrial Ownership With Firm Sales of All Power

Industrial Firm	Excess Power Generated 10^6 kW-h/yr	Life-Cycle Cost, 10^6 dollars		Net Present Cost[1] 10^6 dollars
		Base System	Cogeneration System	Cogeneration System
California Paperboard Corp.	38.3	27.6	43.1	25.8[2]
California Portland Cement Co.	---	46.7	61.5	35.6[2]
Exxon Co., U.S.A.	---	156.4	177.5	123.4[2]
Hunt-Wesson Foods, Inc. - canning season[3]	150.2	40.5	84.1	34.9[2]
Hunt-Wesson Foods, Inc. - all year Alt. 1[4]	---	48.6	48.0[5]	46.2[2]
Hunt-Wesson Foods, Inc. - all year Alt. 2[6]	362.3	48.6	129.4	13.8[2]
Kaiser Steel Corp.	---	199.1	290.5	235.0
Kelco Co.	135.2	57.0	94.3	54.7[2]
Owens-Illinois, Inc.	---	40.5	46.4	37.5[2]
Simpson Paper Co.	46.6	121.9	102.7[5]	52.5[2]
Simpson Timber Co.	---	29.2	29.5	28.7[2]

Table 4-2. Life-Cycle Cost Comparisons: Industrial Ownership With Firm Sales of All Power (Continuation 1)

Industrial Firm	Excess Power Generated 10^6 kW-h/yr	Life-Cycle Cost 10^6 dollars		Net Present Cost(1) 10^6 dollars
		Base System	Cogeneration System	Cogeneration System
Spreckels Sugar Co.	---	63.4	68.1	58.9(2)
Union Oil Co.	---	186.7	221.2	125.5(2)

(1) Cogenerated power sold at 19.5 mills/kW-h. Required power purchased at base system rate.

(2) More attractive than base system when costs are reduced by the receipts.

(3) Cogeneration system sized to meet canning season steam requirement and operates only during canning season.

(4) Cogeneration system sized to meet off-season steam requirement and operates all year.

(5) Life-cycle cost less than base system life-cycle cost.

(6) Cogeneration system sized to meet canning season steam requirement and operates all year, dumping steam during off-season.

The calculated incremental internal rate of return for cogeneration systems in Category B is shown in Table 4-3. Columns 1 and 2 represent the calculated internal rate of return for selling power at the estimated upper and lower bound, respectively, of prices for the sale of cogenerated power. It is noteworthy that only the Hunt-Wesson canning season alternative has an unacceptable internal rate of return for the lower bound price (column 2). These results are consistent with those from the net present cost comparison. The most significant result, however, is that selling all cogenerated power at a price that is lower than what the industrial firm pays the utility can result in an acceptable rate of return. With the exception of Kaiser Steel, all the alternatives have an incremental internal rate of return that is acceptable when compared to the required rate of return.

The life-cycle costs for the base system and the cogeneration system for the two tax incentives are shown in Table 4-4. While both incentives reduce the life-cycle cost for the cogeneration system, neither one alters the economic viability of the cogeneration system when evaluated on a life-cycle cost basis. The base system life-cycle costs for California Paperboard, Hunt-Wesson (two alternatives), and Kelco are still lower than the corresponding cogeneration system life-cycle costs under each incentive. Thus, based on this analysis, the effect that either financial incentive will have toward encouraging the installation of cogeneration by industrial firms is inconclusive.

D. CONCLUSIONS AND RECOMMENDATIONS

1. Institutional

Policies to remove the institutional barriers and develop incentives for Category B are the most difficult to implement inasmuch as both the utilities and the industrial firms want to see certainty in a changing world. In such a world, agreements on a definitive policy determination on regulatory, economic, and contractual positions are difficult to reach.

As a positive first step, the state legislature would need to pass legislation explicitly defining the status of a cogenerator. The National Energy Act legislation could reduce the importance of such a statement if the Federal Power Act provisions are found to apply to cogenerators.

Given a resolved regulatory environment, it will then be up to the industrial firm and the utility to produce contractual agreements. One can expect that after a few "test" cases are completed, the number of firms seriously considering cogeneration will increase dramatically.

At this time, the PUC can only encourage the necessary interaction between the utilities and potential cogenerators, an activity already being pursued by the PUC as discussed in Appendix B.

Table 4-3. Calculated Incremental Internal Rate of Return: Industrial Ownership With Firm Sales of Power

Industrial Firm	Incremental Internal Rate of Return, %			Required Rate of Return (After Tax), %
	(1)	(2)	(3)	
California Paperboard Corp.	21	12.5	16.3	12.5
California Portland Cement Co.	--	--	19.2	10.0
Exxon Co., U.S.A.	--	--	36.2	12.5
Hunt-Wesson Foods, Inc. - canning season	19	1.3	13.3	10
Hunt-Wesson Foods, Inc. - all year, alt. 1	--	--	40	10
Hunt-Wesson Foods, Inc. - all year, alt. 2	34.9	13.2	25.3	10
Kaiser Steel Corp.	--		<0	15
Kelco Co.	30.5	17.7	17.6	15
Owens-Illinois, Inc.	--	--	18.8	12
Simpson Paper Co.	>40	>40	>40	12
Simpson Timber Co.	--	--	36.1	12
Spreckels Sugar Co.	--	--	>40	10
Union Oil Co.	--	--	33.8	10

(1) Excess by-product power sold at base system rate.

(2) Excess by-product power sold at 14 mills/kW-h.

(3) All cogenerated power sold at 19.5 mills/kW-h.

Table 4-4. Effects of Two Financial Incentives: Industrial Ownership With Firm Sales of Excess By-Product Power

Industrial Firm	Capital Investment, 10^6 dollars	Life-Cycle Cost, 10^6 dollars			
				Financial Incentive	
		Base System	Current 10% Investment Tax Credit	20% Investment Tax Credit	6% Interest Loan
California Paperboard Corp.	3.7	27.6	34.5	33.8	32.2
Hunt-Wesson Foods, Inc. - canning season(1)	13.7	40.5	79.6	76.9	73.7
Hunt-Wesson Foods, Inc. - all year, Alt. 2(2)	13.7	48.6	121.6	118.9	115.7
Kelco Co.	8.2	57.0	75.5	73.9	69.0
Simpson Paper Co.	8.1	121.9	23.1	21.5	18.3

(1) Cogeneration system sized to meet canning season steam load and operates only during canning season.

(2) Cogeneration system sized to meet canning season steam load and operates all year, dumping steam during the off-season.

2. Environmental

As with the BACT provision discussed in Section III, there appears to be a large difference between the viewpoints of industry and the environmental regulators. Based on discussions with the regulators, the following recommendations are made:

(1) A joint ARB/APCD committee should be established to specify implementation guidelines for conducting an Air Quality Impact Analysis. The committee should have industry and environmental interest group representation. Included in the guidelines should be a clearer delineation of (a) the method by which trade-off ratios are determined, and (b) what constitutes a legally enforceable inter-firm contract.

(2) Based on these guidelines, individual APCDs should produce specific procedures for evaluating trade-off applications. This could help the firms understand the basis for the process.

(3) The ARB should give consideration to the possibility of cross-pollutant trade-offs for air basins with zones having different air pollution problems. In addition, consideration should be given to implementing inter-basin trade-offs. The problems in administering cross-pollutant and inter-basin trade-offs should not be underestimated - they involve legal, public health, and equity questions that have not yet been analyzed.

These recommendations offer opportunities for supporting industrial cogeneration ventures without undermining air pollution mandates.

SECTION

ANALYSIS OF CATEGORY C: UTILITY OR THIRD PARTY OWNERSHIP

Under utility or third party ownership of the cogeneration facility, the electric utility invests its capital in the cogeneration equipment located at the industrial firm. The utility operates the cogeneration facility to meet the steam requirements of the industrial plant. Given this constraint, the utility then runs the facility as part of its total generation capacity.

A. INSTITUTIONAL ISSUES

The advantage for the firm in this arrangement includes the ability to look at the steam supply as an annual expense as opposed to a capital expenditure. "Corporate income tax rates (encourage) the substitution of expenses for capital investment" (Reference 1, page 22). When buying steam, the firm reduces its need for staff to oversee steam supply system maintenance. The disadvantage is that the firm is subject to the utility's determination of the proper price for the delivered steam. The negotiated contract for steam must take into account the firm's need for a fixed supply at a reasonably determined price, i.e., less expensive than the firm's other alternatives, but with the capability to terminate the contract if it decides the plant is no longer economic to run. The contract must also take into account the utility's need for assurance that the firm will not close and result in a cogeneration plant without a steam customer. Without the steam customer, the plant would become very expensive for the utility to run.

Other advantages for the firm are the lack of any concerns over regulation of their firm by federal or state authorities and the avoidance of many of the issues raised, e.g.:

- Selling price for electricity
- Determination of standby rates
- Changes in natural gas priorities as a result of entering into a cogeneration agreement. In fact, many of the firms fuel supply concerns are alleviated under this arrangement and are placed on the utility.

Advantages of utility ownership for the utility are (1) continuing control over electrical generation and (2) retaining the existing (and preferred) industrial customers. Disadvantages include (1) the concern over the continuity of its steam customer, (2) the need to acquire the necessary capital, and (3) the lengthy siting procedures.

Capital requirements for future utility capacity expansion are a problem for many utilities whether for cogeneration plants or central station plants. However, for the three California utilities, capital commitments have already been made for near-term expansion. To raise capital for cogeneration projects, the utility must either acquire new capital or back off on planned projects.

The other restraint is on plant siting. Utility-owned plants are subject to the complete Notice of Intent/Application for Construction permit procedure administered by the California Energy Resources Conservation and Development Commission (CERCDC). This procedure can legally take up to 36 months, but in practice can last much longer. If the plant is between 50 and 100 MW, the procedure can be expedited under the "Small Power Plant Exemption."* State legislation has been proposed to expedite the siting of power plants which utilize cogeneration technology. Under AB2046, three alternative sites will not be required and the decision of the CERCDC must be issued within nine months from the date of filing of the proposed construction and within nine months of the subsequent filing of the application for certification. Although this will help the utilities, it is still an involved procedure. These procedures hold for both investor-owned and municipal utilities.

The cogeneration provision in the pending National Energy Act legislation applies only to "persons not primarily engaged in the generation or sale of electric energy." As a result, utility-owned cogeneration plants might be placed at a disadvantage when and if the incentives in the National Energy Act are passed.

1. Primary Issues

a. Long-Term Agreements. There is a striking difference between the planning horizon of an industrial firm and that of a regulated electric utility company. This difference could result in contractual problems when agreements are required between the two parties. The utility is concerned with investments that will produce returns over a 10 to 30 year period. The firm is more interested in the immediate return and its effect on its short-run profitability. The utility is insured by the PUC that it will be viable in the long run. The firm has no such guarantee.

The Industrial Firm's Viewpoint

The problem for the California Paperboard Corporation was the requirement, imposed by the City of Santa Clara Electric Department, of a guarantee that California Paperboard would stay in business for a specific period of time. California Paperboard would have no capital invested in the project. However, there would be a contingent liability if the firm closed the facility. Because of this liability, the requirement for a long-term guarantee presented a problem from the industry viewpoint.

*Memorandum from the CERCDC to the Department of Finance, January 28, 1978. A power plant under 50 MW is not under the jurisdiction of the CERCDC. The CERCDC would not have jurisdiction in the siting of plants under Category A.

A similar situation faces the Husky Oil Company in its negotiations with PG&E to supply oil to the utility in return for steam. PG&E wants a long-term guarantee for a continuous supply of oil for the cogeneration power plant. If Husky Oil is unable to meet PG&E fuel demands, then $15/bbl oil might have to be purchased and supplied to PG&E at $7/bbl.

These two examples demonstrate the need for the industrial firm to accept the long-term risk associated with cogeneration; however, some firms are not in a position to accept this risk.

The Electric Utility Company's Viewpoint

All of the utilities recognize the significance of the different planning horizons used by utilities and industrial firms. This is one reason why they are reluctant to invest in cogeneration schemes. The fact that the annual revenue per dollar invested in utilities is typically small forces the utility to consider only those investments that can be relied on for over 15 years.

Summary of the Issue

Not all industrial firms have short-term planning horizons. According to PG&E, some of its industrial customers have 15-20 year plans, comparable to those of the utilities. However, for those firms without a long-term planning horizon and who are therefore reluctant to make long-term investments, the contrast in planning horizons can give rise to a significant impasse. If the utilities continue to place the risk on the firm, the number of potential cogenerators will probably decrease. Until a larger number of contracts have been negotiated, further analysis would be speculative.

b. Steam Sales. The sale of by-product steam to the firm has many of the characteristics of the problems of joint supply (Reference 21, pp. 53-66). The classic example is that of the production of wool and mutton from sheep raising. How much of the cost of raising the sheep should be attributed to the production of wool? How much should be attributed to the production of mutton?

As an example, let us assume that a firm and an electric utility, each using 1 barrel of oil, could produce X pounds of steam and Y kilowatt-hours of electricity. However, if they cogenerate, 1-1/2 barrels of oil could produce X pounds of steam and Y kilowatt-hours of electricity. Should the reduction of 1/2 barrel of oil be attributed to steam production or electricity production? If the utility determines that the reduction is to be shown in the cost of steam produced, then steam users will have reduced costs and will capture the productivity gain. Alternatively, if the utility determines that the reduction is to be shown in the cost of electricity produced, then electricity customers will capture the productivity gain. Although one can argue that the truth lies somewhere in between, it is not possible to say precisely where. Therefore, both customers will always have a potential complaint.

In an unregulated market, the differences in demand and available alternative production opportunities would help to determine the optimal prices. However, the nature of a public utility with its fixed, or at least slowly changing, tariff for electricity will prevent this from happening. Because steam tariffs are more flexible, the utility might allocate the current cost of electricity production (1 barrel) to electricity production and negotiate for the best possible price for steam. The net result would be that the reduction in the cost of electricity production by cogeneration is not passed on to the electricity customer. If, on the other hand, the utility does try to pass on the savings to its electricity customers, the sale price for steam might need to be higher than industrial firms are willing to pay. The firm would probably be unwilling to enter into such an agreement.

The Industrial Firm's Viewpoint

From the industrial firm viewpoint, a cogeneration system where steam is purchased from the utility will be acceptable only if the purchase price is less than the firm's present steam production cost. California Paperboard Corporation saw the need for a 5 to 10% reduction. Kelco was not specific but did note the need for a reduction in the price in order to enter into a cogeneration agreement with SDG&E.

The Electric Utility Company's Viewpoint

San Diego Gas and Electric Company has taken the view that the cost of electricity from cogeneration is equivalent to other generating plants and that the savings from cogeneration are passed on to the steam customer. For example, the investment at Rohr Industries is estimated to save the industrial firm $90,000 per year as a result of purchasing steam from the utility (Reference 22). The two other major California public utilities have not made any final determination on how steam prices will be set.

Summary of the Issue

A consumer will accept a range of prices for steam and electricity; the determination of the actual sale price within that range is normally set by the market. In this case, however, since the PUC oversees the determination of the socially optimal prices, all of the cost savings are not automatically passed on to the consumer.

2. Secondary Issues

a. National Energy Act. The original draft of legislation for a comprehensive national energy policy defined a qualifying cogenerator as one who meets certain requirements and, in cases where the cogeneration facility is to be directly connected to an electric utility, has offered the utility the opportunity to construct and operate the equipment. Such a definition would have helped encourage utility recognition of potential cogeneration. However, subsequent drafts of the legislation have altered the definition as noted in Section III-A-1-b. The result is that the proposed legislation does not encourage electric utilities to consider cogeneration.

3. Inappropriate Issues

Many of the identified issues do not affect the implementation of utility-owned cogeneration systems. One reason for this is that only three of the surveyed firms are considering this arrangement. In addition, the firm and the utility retain their existing roles - the utility supplying intermediate goods to industry and the firm converting them into a final product. Because of this, the concern about (1) the selling price of electricity, (2) regulation, (3) standby rates, (4) natural gas priorities, (5) wheeling, and (6) the changes in the electric utilities rate design are not influential in the implementation of utility-owned cogeneration systems.

B. ENVIRONMENTAL ISSUES

A major advantage to an industrial firm in Category C is that the burden of obtaining environmental permits is placed on the electric utility. The significance of the New Source Review (NSR) rules is unchanged, but now the electric utility must take the lead in applying for permits.* In other words, all the problems discussed previously on Best Available Control Technology (BACT) and Air Quality Impact Analysis (AQIA) must now be addressed by the electric utility.

Under the model NSR rule, a source is defined as an aggregation of units which, among other conditions, must be "under the same ownership or entitlement to use and operate." Under Category C, the electric utility owns the cogeneration system; thus the cogeneration boiler is considered to be a separate source from the industrial firm's plant. This makes it easier (and less expensive) to comply with the BACT provision at the source (which is now just the electric utility's cogeneration plant) and also easier to comply with AQIA since improvements in the industrial firm's coterminous plant could be used as trade-off (see Figure 3 in Appendix H). This is precisely what occurred in the San Diego Air Pollution Control District when Applied Energy, Inc., a wholly-owned subsidiary of San Diego Gas and Electric Company, began to acquire permits to operate a cogeneration system at a facility of Rohr Industries. In this case, trade-offs with two of Rohr's boilers were used in conjunction with a requirement to burn low sulfur fuel.

The California Air Resources Board (ARB) recognizes this loophole created by the legal formalism of the definition of a source. However, the ARB has indicated that the law would be changed if it was overused or was influential in keeping the air basin from meeting its ambient standards.

As an example of a Category C arrangement, consider the case of the California Paper Board Corporation (CPC). After the initial engineering analysis, CPC and the local electric utility, a municipal utility

*The analysis in this study concentrated on those issues affecting the industrial firm's decision; the electric utility's position on the NSR rules was not examined.

owned by the City of Santa Clara, agreed to proceed with a Category C arrangement. In September 1977, the City applied for a permit to construct under the existing NSR rules in the Bay Area Air Pollution Control District. In November, the City was advised that its cogeneration project did not meet the existing standards but that the use of a taller stack to disperse the pollutant would allow the project to receive a permit to construct.* In December, the ARB adopted a new NSR rule for the Bay Area in line with the model rule discussed in this report. Now the project must be evaluated on the basis of emissions. The City modified the plant to reduce emissions from 67 pounds per hour to 35 pounds per hour. Thus, an Air Quality Impact Analysis was still required. The lack of industry in the area made it almost impossible for the plant to find trade-offs. In March, the City was formally denied their first application. The City requested an exemption under the premise that cogeneration was an innovative control technology, one of the several exemptions available under the Air Quality Impact Analysis section of the NSR rules. The ARB denied the required concurrence and the City appealed to the Bay Area APCD Hearing Board. The case has not yet been heard, although preliminary hearings were held in July 1978. Thus, despite utility ownership of the cogeneration facility, the industrial firm can still be subjected to the frustrations of delayed plans.

C. ECONOMIC CONSIDERATIONS

Three of the industrial firms, California Paperboard, Husky Oil, and Kelco, have the alternative of purchasing steam and electricity. The life-cycle cost for the cogeneration system under this ownership alternative is highly dependent on the price of steam to the industrial firm. The steam price assumed for California Paperboard is based on detailed information obtained from the firm and should be a good estimate; however, the prices for steam to Husky Oil and Kelco were estimated under more arbitrary conditions and may not accurately reflect the actual price. In addition to computing the life-cycle cost based on the assumed steam price for each site, the break-even steam price was also calculated for each site. The results are presented in Table 5-1.

Based on the assumed steam price for each site, only California Paperboard has a life-cycle cost that is lower than the base system life-cycle cost. However, the calculated break-even steam prices for Husky Oil and Kelco are very close to that for California Paperboard, with a variance of less than 7% from one another despite the uniqueness of each cogeneration system. It is also significant to note that for Husky Oil, a 9¢ reduction in the steam price results in an economically viable system.

Thus, the price of steam to the industrial firm is extremely important. In addition, a firm may be more likely to consider this cogeneration option than some of the other options discussed because it relieves the firm of the problems associated with producing steam and does not alter the normal procedure of purchasing electricity from the utility.

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*The NSR rule operating in the Bay Area APCD at that time was based on the effect on ground level concentrations rather than on emissions.

Table 5-1. Life-Cycle Cost Comparison: Utility or Third Party Ownership

Industrial Firm	Life-Cycle Cost, 10^6 dollars		Steam Price, $\$/10^3$ lb	
	Base System(1)	Cogeneration System	Assumed Price	Break-Even Price(2)
California Paperboard Corp.	27.6	26.6	3.25	3.39
Husky Oil Co.	236.4	326.5	3.35	3.26
Kelco Co.	57.0	75.4	4.50	3.18

(1) Base system refers to the current method of steam production in the plant. Husky Oil currently does not have a steam production system and a hypothetical system, based on an actual system at another oil field, was used.

(2) Required price for steam that will equate cogeneration system cost with base system cost.

The internal rates of return, assuming utility or third-party ownership of the cogeneration facilities (see Table 5-2), reflect the results of the life-cycle cost comparisons. The conclusion that this option is not viable for Kelco and Husky cannot be made, however, because of the uncertainty in the estimate of the steam price.

Table 5-2. Calculated Incremental Internal Rate of Return: Utility or Third Party Ownership

Industrial Firm	Calculated Incremental Internal Rate of Return, %
California Paperboard Corp.	>40
Husky Oil Co.	<0
Kelco Co.	<0

D. CONCLUSIONS AND RECOMMENDATIONS

Almost all of the technical, economic, and legal analysis has emphasized cogeneration by an industrial firm. In addition, policy developments at the federal and state level have emphasized industry-owned cogeneration. Based on the advantages of Category C, it appears that such emphasis deserves reconsideration. Section 115 of the proposed Public Utilities Regulatory Policy Act of 1977 addresses the need for such a study.

The inclination of industrial firms and utilities to enter into Category C agreements would be affected if the PUC could minimize the risk to the two entities. Typically, firms appear to be reluctant to accept liability for the consequences should circumstances force them to cease operations at the plant. Utilities, however, do not want to enter into agreements where they would assume the liability of operating cogeneration equipment for just the production of electricity. If the PUC could assure the utility that adequate rate relief would be made quickly available if such cogeneration arrangements were prematurely terminated, the firms' and the utilities' concern over the sharing of the associated financial risk would be reduced. The risk would be borne by the ratepayers. The decision before the PUC is how to allocate the risk associated with industrial cogeneration, while at the same time encouraging cogeneration to help reduce the price of electricity. In the past, the efforts of the PUC appear to have been towards placing the risk on the utility's stockholders and passing on the benefits to the ratepayers. Whether this can continue successfully with cogeneration is still being debated. In the meantime, some utilities want the firms to accept the risk. The differences among the three major public utilities are examined in Appendix C.

APPENDIX A

GLOSSARY

This glossary contains a list of terms frequently used in discussions of cogeneration. The selection of terms was based on experience with the relevant literature. Sources for the terms are contained in the Bibliography.

APCD

Air Pollution Control District

AQMA

Air Quality Maintenance Area

ARB

Air Resources Board

Base Load

The minimum load of electric power which is generated or supplied continuously over a period of time.

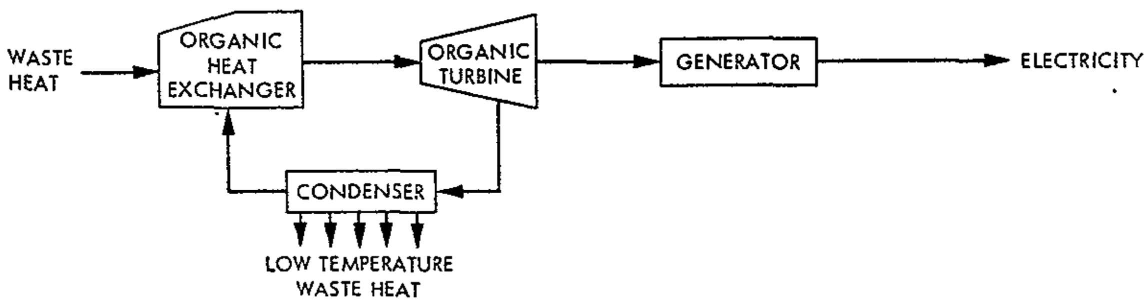
Bottoming cycle

Waste heat from an industrial process is utilized for the generation of electricity.

Bottoming cycle, combined/organic

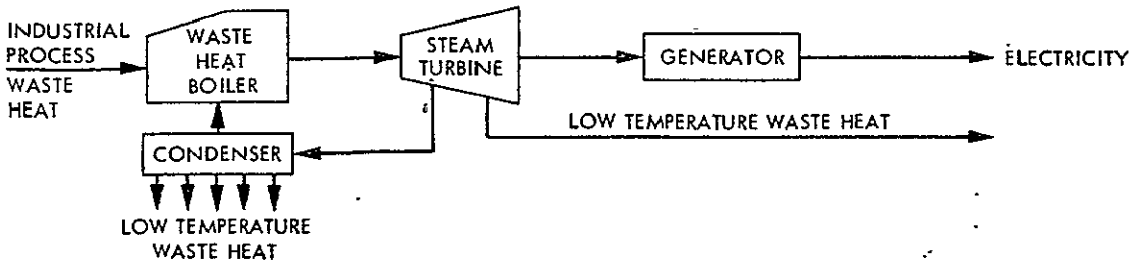
Waste heat from a gas/steam turbine is utilized for the generation of electricity in an organic bottoming cycle.

Bottoming cycle, organic



The utilization of low temperature waste heat from an industrial process for the generation of electricity in a system using an organic working fluid.

Bottoming cycle, steam



The utilization of waste heat from an industrial process for the generation of electricity using a steam turbine.

Brayton cycle

A reversible thermodynamic cycle which describes the heat to work conversion process in a gas turbine power plant.

By-product power

Power which is generated in conjunction with an industrial process which optimizes or matches the generation of electricity to the steam and/or heat requirements.

Capacity

The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer.

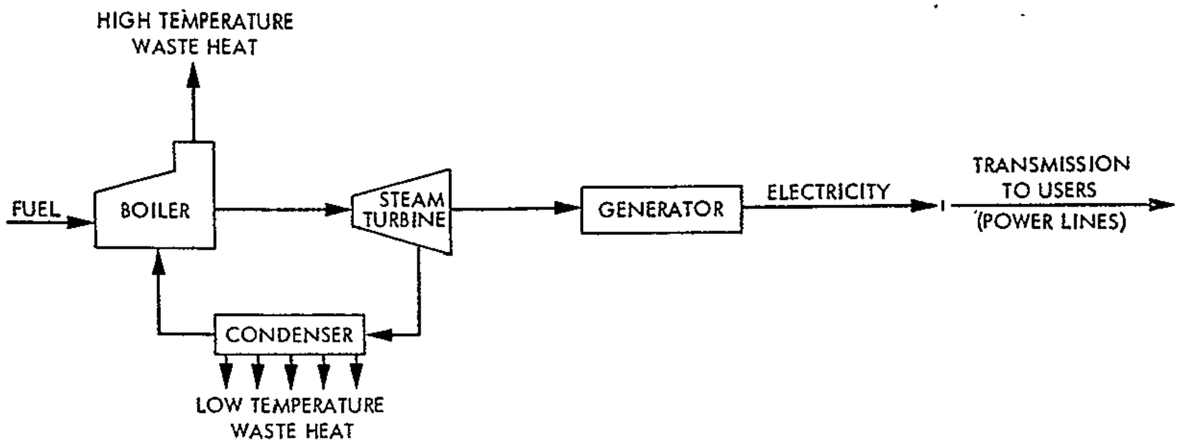
Capacity factor

The ratio of the average load on a machine or equipment for the period of time considered to the capacity rating of the machine or equipment.

Capital cost

Cost of construction of new plant (additions, betterments, and replacements) and expenditures for the purchase or acquisition of existing facilities.

Central power generation, steam



Electricity generated by a utility at a large power generating plant, the primary purpose of which is the generation of electricity.

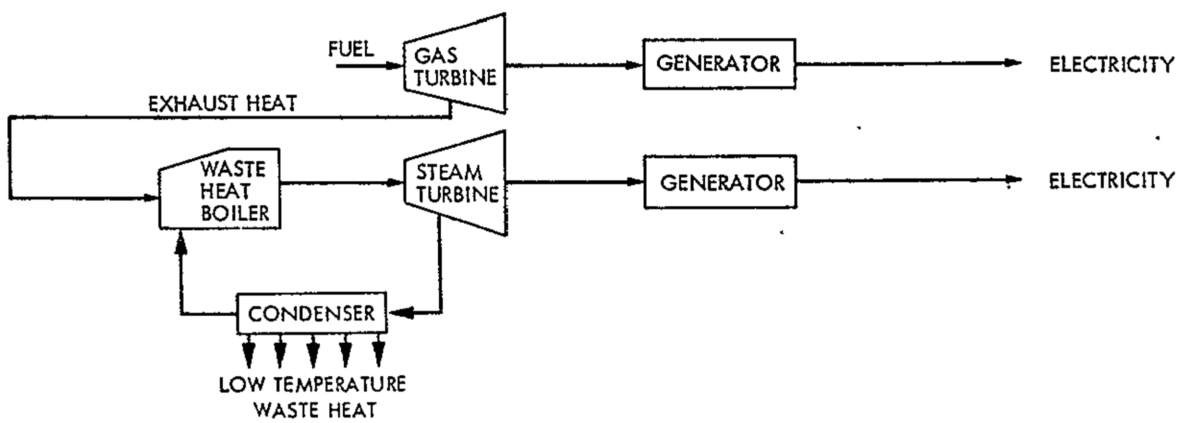
CERCDC

California Energy Resources Conservation and Development Commission

Cogeneration

The generation of process steam, process heat or space conditioning combined with the generation of electrical power which leads to an efficiency of fuel utilization greater than that resulting from the independent generation of equivalent units of process steam, process heat, space conditioning, and electrical power.

Combined cycle



Waste heat from a gas turbine topping cycle is utilized for the generation of electricity in a steam turbine/generator system.

Condensing power

Power generated through a final steam turbine stage where the steam is exhausted into a condenser and cooled to a liquid to be recycled back into a boiler.

CPUC

California Public Utilities Commission

Dual-purpose power plant

See cogeneration.

Engine topping

See topping cycle.

Feedstock

With respect to cogeneration, it is the type of fuel supply to a combustion process for the production of heat used for energy conversion to steam or electricity.

Field assembled boiler

A high pressure boiler which usually has a large capacity. Generally oil and gas fired, it can also burn solid fuels and costs about $40-45/lb of steam per hour.

Fuel allocation

Natural gas is allocated by the priority basis consistent with defined end-uses. Priorities, from a high of P1 to a low of P5, are effective May 31, 1976.

Grid

A utility's power generation, transmission and distribution system, including transmission lines, transformer stations, etc.

Heat rate

A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Heat recuperators

Equipment used to recycle heat back into the process creating a higher thermal efficiency of the overall process.

High grade waste heat

Waste heat in the high temperature range of 1000°F or above which can be used for power generation in a steam turbine.

Hog fuel

A waste product of the lumber industry consisting of coarse residue and sawdust which can be used as by-product fuel.

Industrial cogeneration

Power generation at an industrial site using either a topping cycle or a bottoming cycle.

Industrial dual-purpose power plant

See industrial cogeneration.

Industrial steam

Steam that is produced as part of the industrial process.

In-plant generation

See industrial cogeneration.

Internal rate of return

The discount rate which equates the present value of expected future receipts to the cost of the investment outlay.

Interruptible power

Power made available under agreements which permit curtailment or cessation of delivery by the supplier. Advance notice is usually given from 1 to 1-1/2 hours prior to the interrupt.

Investment tax credit

A specified percentage of the dollar amount of new investment in each of certain categories of assets that a firm can deduct as a credit against their income tax bill.

Load

The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customers.

Load factor

The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load occurring in that period.

Low grade waste heat

Waste heat in the temperature range of less than 1000°F.

Megawatt (MWe)

One thousand kilowatts of electric power.

Net present value

A capital budgeting method which takes into account the time value of money through discounted cash flow analysis. The method determines the present value of the expected net revenue from an investment minus the cost outlay, discounted at the cost of capital.

New Source Review Rules

Adopted by the California Air Resources Board, these rules constitute a set of guidelines to be used by state and pollution control officers when ruling on permits to construct new stationary sources or modifications to existing stationary sources.

Operating cost

A group of expenses applicable to operations.

Package boilers

A low pressure boiler, usually small enough to be shop assembled. It generally burns gas or liquid fuels and costs about $10/lb of steam per hour.

Parallel generation

Industrial power generation facilities whose AC frequencies are exactly equal to and operate in synchronism with the utility service grid.

Payback period

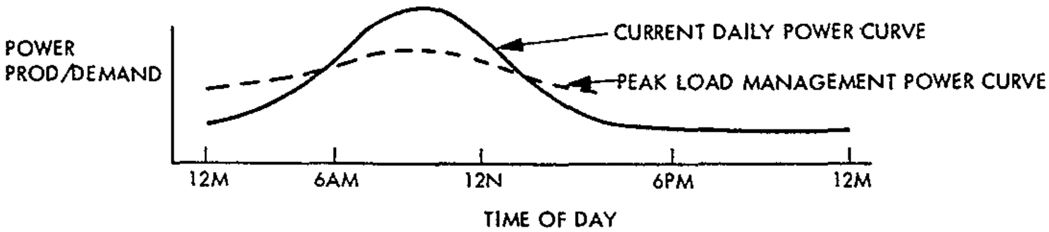
The number of years required for a firm to recover the original investment from net returns before depreciation but after taxes.

Peak load

The maximum of all demands of the load which has occurred during a specified period of time.

Peak load management

An attempt to reduce the system peak load by leveling the daily power curve.



Power factor

The ratio of real power to apparent power for any given load and time. Generally, it is expressed as a ratio.

Preheaters

Equipment used to pre-heat the intake air prior to entering a combustion process creating a higher thermal efficiency for the overall process.

Present value

The present value of a cash flow is its real value adjusted for the interest that could be earned, or must be paid, between the time of the actual flow and the specified "present" time.

Process heat

Heat used for the industrial process of a plant and not the housekeeping chores such as space heating.

Process Steam

See industrial steam.

Process steam load

Number of pounds of steam per hour required for a specified industrial process.

Rankine cycle

A reversible thermodynamic cycle which describes the heat to work conversion process in a steam power plant.

Rate base

The value of assets, established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return. Generally, this represents the amount of property used and useful in public service.

Sinking fund

Cash or other assets, and the interest or other income earned thereon, set apart for the retirement of a debt, the redemption of a stock, or the protection of an investment in depreciable property.

Spinning Reserve

Generating capacity which is on-line and ready to take load, but in excess of the current load on the system.

Standby power

See standby service.

Standby reserve

See standby service.

Standby service

Service that is not normally used but which is available through a permanent connection in lieu of, or as a supplement to, the usual source of supply.

Sunk costs

Costs which have already been committed and thus are irrelevant to future investment decisions.

Surplus electricity

Energy generated that is beyond the immediate needs of the producing system. This energy is frequently obtained from spinning reserve and sold on an interruptible basis.

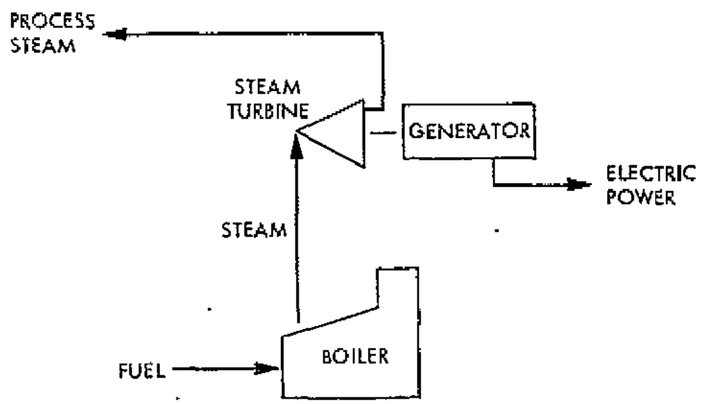
Thermally integrated energy system (TIES)

The electric power output of the local power generation plant goes into the utility company distribution grid, rather than directly to the user. The user is served power from the grid but also receives heating and cooling media produced from power generation by-product heat from the TIES plant.

Topping cycle

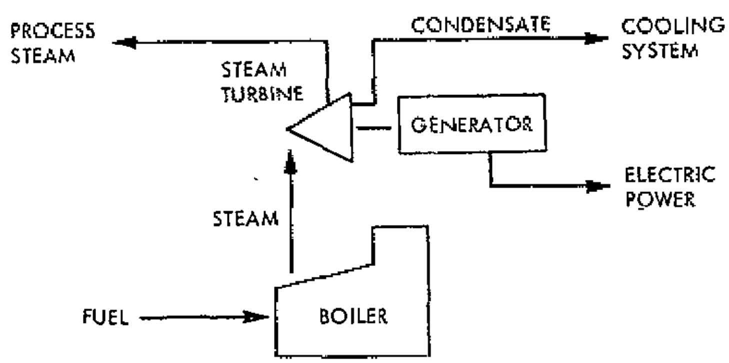
Energy is first used to generate electricity then used in an industrial process.

Topping cycle, back-pressure steam turbine



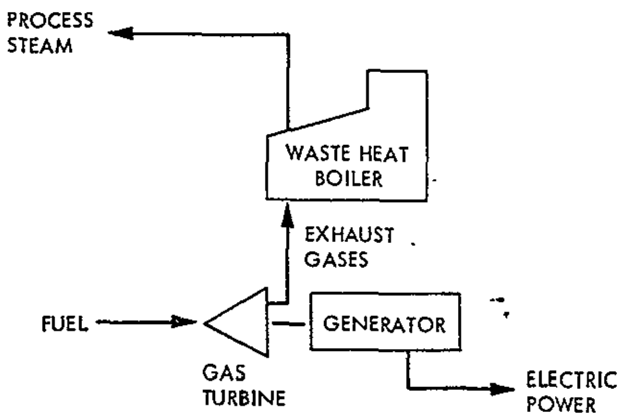
Steam is generated in a boiler then sent through a turbine-generator, producing electricity. The steam is discharged from the last stage of the turbine at pressures needed for industrial process use.

Topping cycle, extraction steam turbine



This system operates in a similar manner to the back-pressure steam turbine, except that steam is extracted at different pressures from intermediate stages of the turbine and used in industrial processes, while the steam exhausting from the final stage is condensed and returned to the boiler for reuse.

Topping cycle, gas turbine/waste heat boilers



Compressed air and a gaseous fuel or light petroleum product are fired in a gas turbine. The hot combustion gases pass through a turbine-generator, producing electricity. The hot exhaust gases from the turbine are passed over water-filled tubes in a waste-heat boiler, producing steam at pressures needed for industrial process use.

Total energy system

On-site generation of electricity with beneficial use of waste heat.

Turbine

An enclosed rotary type of prime mover in which heat energy in steam or gas is converted into mechanical energy by the force of a high velocity flow of steam or gases directed against successive rows of radial blades fastened to a central shaft.

Utility cogeneration

Utilization of waste heat from a central power generating plant to produce either thermal energy to sell for space or process heat, or additional electrical energy.

Utility dual-purpose power plant

See utility cogeneration.

Waste heat

Unused thermal energy which is exhausted to the environment from an electric generation system or an industrial process.

Wheeling

The use of the transmission facilities of one system to transmit power of and for another system.

Wheeling charges

Cost of wheeling power.

Working capital

The amount of cash or other liquid assets that a company must have on hand to meet the current costs of operations until such a time as it is reimbursed by its customers.

APPENDIX B

THE CALIFORNIA PUBLIC UTILITIES COMMISSION

I. RESPONSIBILITIES

The California Public Utilities Commission (PUC) is responsible for regulating certain privately owned facilities and transportation companies and to secure for the public adequate services at rates that are just and reasonable. As one of the boards, commissions, and independent units in the California State government, this administrative agency has both legislative and judicial powers:

> "It (the PUC) may take testimony in the same manner as a court; issue decisions and orders, it may site for contempt and may subpoena records."
> (Reference 23, page 7.)

Although its powers have been described as unusually broad, its decisions may be appealed to the Supreme Court.

Specific responsibilities of the California Public Utilities Commission include:

(1) Establishing retail rates for the services from regulated utilities (establishing wholesale interstate and wholesale intrastate rates is now the responsibility of the Federal Energy Regulatory Commission).

(2) Regulating service and facilities from public utilities to insure safety, reliability, and adequacy.

(3) Authorizing sale of securities by the public utilities.

(4) Establishing accounting procedures for public utilities.

(5) Reviewing of all special contracts for the reasonableness of expenses.

In February 1975, PUC jurisdiction over the adequacy of electric generation facilities was curtailed by a revision of General Order 131 (June 1970). Originally, G.O. 131 made the PUC responsible for annual 10-year forecasts and biennial 20-year forecasts of load demand and supply capability for each utility. The California Energy Resources Conservation and Development Commission (CERCDC) now has the responsibility to review and assess these plans. The only forecasts reviewed by the PUC, as revised by General Order 131A (February 1976), are 10-year forecasts of planned and/or needed transmission lines (References 24 and 25, Section 2). Thus the CERCDC, rather than the PUC, is more influential in determining the applicability of a cogeneration

system's capacity to the forecasted supply capability of each utility. The PUC is still responsible for determining that plants over 50 MWe planned by the public utilities under its jurisdiction

> "... are necessary to promote the safety, health, comfort and convenience of the public, and that they are required by the public convenience and necessity." (Reference 24, Section 1.)

In the determination of the public's energy needs, the PUC could allow available cogeneration facilities to be taken into consideration. However, because of the length of the utility resource planning cycle, usually about five years, the importance of cogeneration delaying the need for new capacity will be heavily determined by the CERCDC.

II. ACTIVITIES RELATED TO COGENERATION

Regulation of electric utilities is only one of many activities under the jurisdiction of the PUC. Although the PUC regulates over 500 utilities (Reference 24, page 62), only 13 are electric utilities. However, of the $10 billion per year of operating revenue under PUC regulation, $3.5 billion is attributable to these 13 electric utilities (Reference 16). Two of these utilities, PG&E and SDG&E, are also steam utilities with annual revenues from steam sales of approximately $3 million (Reference 23, page 66).

The PUC's Decision No. 85559 (March 1976) on Case No. 9804, ordered the utilities in California "to cooperate and evaluate waste heat proposals to be submitted by" large industrial firms. "Electric utility rate structure and conservation" was the subject of the case. In addition, the utilities were also ordered to provide the PUC with a "status report on existing waste heat electric generating plants and utilization of waste heat from" the utilities' "generating facilities for industrial and commercial purposes." (Reference 26, page 7.)

Until January 1978, the PUC did not exhibit active involvement in encouraging industrial cogeneration, other than requesting the reports required by Decision No. 85559. In January 1978, the PUC took what they described as a "significant first step" by adopting Resolution No. E-1738 (January 10, 1978) and approving the Staff Report on California Cogeneration Activities (January 17, 1977). These are discussed below.

Resolution No. E-1738 - Order Directing Electric Utilities to Augment Cogeneration Projects

The resolution finds that there has been "insignificant progress" since Decision No. 85559 by the three major electric utilities (PG&E, SCE, and SDG&E) in installing, negotiating for, and developing cogeneration. Cogeneration is defined by the PUC in the resolution as a "more efficient method of optimizing electrical and heating requirements and will result in both a reduction in the use of imported fossil fuels to generate electricity and the cost of electric generation."

The resolution also points to the need to evaluate the appropriateness of existing "rates for standby service and prices paid for energy purchased from cogenerators." The availability of interruptible service is also mentioned, but it is not directly tied to its influence on promoting cogeneration.

The resolution ordered the three major electric utilities to:

(1) Propose a rate schedule for expanding interruptible electric service.

(2) Propose other "rate proposals to enhance cogeneration, including revisions to standby rates."

(3) Submit "guidelines covering the price and conditions for the purchase of energy and capacity from cogeneration facilities owned by other."

(4) Submit "a report on guidelines for development of utility owned cogeneration facilities."

At the time the present report was being written, these items were being pursued. The utilities' initial responses were not received in time to describe and analyze them in this report.

Staff Report on California Cogeneration Activities

The Staff Report on California Cogeneration Activities serves as necessary background and support of the PUC's resolution. In addition to providing useful definitions, descriptions, and analyses of the implications of rate changes for standby power and interruptible service, the staff has listed what the state's three major utilities consider to be sites that have cogeneration potential. Because the firms are not identified, it is not known if all 12 sites referred to in this report are included.

The Staff Report also addresses the concern of some firms that cogeneration will place them under the jurisdiction of the PUC.

> "The staff does not regard the customer who generates all or a portion of electricity for his own use and sells surplus energy to a utility as a public utility and subject to Commission regulation..." (Reference 5, page 8.)

However, this is only a finding by the Staff and not a Commission ruling.

III. JURISDICTION OF THE CALIFORNIA PUBLIC UTILITY COMMISSION AS IT RELATES TO INDUSTRIAL COGENERATION

The Public Utility Code consolidates all the "laws relating to and regulating public utilities and other regulated business." What

then is a public utility? The determination that a particular cogeneration system makes the owner a public utility, and therefore subject to regulation, is a crucial issue that is presently the subject of federal legislation (see, for example, H.R. 4018).

In the Public Utility Code, Paragraph 216 defines a public utility such that it:

(a) "... includes every common carrier, toll bridge corporation, gas corporation, electric corporation, ... where the the service is performed for or the commodity delivered to the public or any portion thereof.

(b) "Whenever any (of the above) ... performs a service or delivers a commodity to the public or any portion thereof for which any compensation or payment whatsoever is received, ... such (a corporation is) a public utility (and) is subject to the jurisdiction, control, and regulation of the commission and the provisions of this part."

This definition appears to be quite broad, but it goes even further in subsection (c):

(c) "When any person or corporation performs any service or delivers any commodity to any person, private corporation, municipality, or other political subdivision of the State which in turn either directly or indirectly, mediately or immediately, performs such services or delivers such commodity to or from the public or some portion thereof, such person or corporation is a public utility subject to the jurisdiction, control and regulation of the commission and the provisions of this part."

Subsection (c) appears to incorporate just about anybody and anything, including a firm that sells a minor amount of electricity to an electric utility for resale to the customers of the electricity utility. The definition is much broader than that used in the discussion of the State Regulatory pattern in the Dow Chemical Company's Report on industrial cogeneration.

"...companies owning or operating facilities devoted or dedicated to 'public use'." (Reference 1, page 371.)

The concept of "devoted or dedicated to public use" also holds in California as a result of the interpretation by the California court. The key decision appears to be that of the courts in 1960 in the case of Richfield Corporation vs. Public Utilities Commission. Here the Supreme Court ruled that the PUC was without jurisdiction in its attempt to regulate an oil and gas producer who was offering to deliver oil and gas to a public utility. The reason given was that the oil and gas producer had not dedicated its facilities to public use.

The major question, then, is how is the concept of "dedicated or devoted to public use" determined? Even this question raises some questions as to which "life" of the boiler should be used -- economic, technical or tax life. The PUC's present position is that

> "Whether a cogenerator can be said to have dedicated its cogeneration facilities to public use is a question the answer to which will depend on the facts of each case."*

Before leaving the question of what determines whether or not a corporation is a public utility, the case of the River Bend G&W Company should be considered. The River Bend G&W Company is a public utility that sold its water distribution system to another company, but agreed to continue to sell water from its well at a fixed rate per month to the new owner of the distribution system. The PUC (at that time the California Railroad Commission) held in 1917 that the River Bend Company did not lose its public utility status nor was it relieved of public utility regulations. The holding in this case appears to apply to any cogenerator. The only difference is that a cogenerating firm was not a public utility prior to cogenerating. In other words, the end state of the River Bend Company Case and a cogenerator selling excess electricity are identical; they differ only in their history of getting to that end state. To review what has been described above, when looking at any cogeneration scheme where electricity is being sold to the grid:

(1) The California Code states that the owners of such a system are under PUC jurisdiction.

(2) The case of Richfield Corporation states that such a facility is not under PUC jurisdiction (pending clarification of the definition of "dedicated to public use").

(3) The "old" case of River Bend G&W Company held that the owner is under PUC regulation.

*Personal communication, M. J. Borak, California Public Utilities Commission, March 3, 1978.

APPENDIX C

THE THREE MAJOR PUBLIC UTILITIES

The Public Utilities Commission staff noted in its report that "the implementation of cogeneration projects require (sic) both a willing buyer and willing seller." (Reference 5, page 8.) With that in mind, this appendix describes the three major electric utility companies in the state: (1) Pacific Gas and Electric Company (PG&E), (2) Southern California Edison Company (SCE), and (3) San Diego Gas and Electric Company (SDG&E). During the course of this study, interview teams met with representatives of each of these utilities to discuss their views on cogeneration. Table 1 presents a comparison of some of the key characteristics of these three electric utilities.

I. PACIFIC GAS AND ELECTRIC COMPANY

Although PG&E services an area twice the size of that served by SCE, their electric system and sales are similar. Electric operations account for 59% of the total revenues and 70% of the operating income. Both of these percentages have been increased in recent years because of the decrease in gas sales. The most recent dramatic change for PG&E occurred during 1976-77 when, as a result of the drought, hydroelectric power contributed only 38% of the total system output. In the years preceding the drought, PG&E was able to use hydroelectric generation (which is less expensive than fossil fuel generation) for more than half of its output (Reference 27, page 6). The effect on the cost of electric energy produced in 1977 was quite dramatic, as shown below:

Cost of Electric Energy (Thousands of Dollars)

	1977*	1976*	% Increase from Previous Quarter
First Quarter	215,432	198,139	9
Second Quarter	257,479	113,824	126
Third Quarter	364,864	159,281	129
Fourth Quarter	337,365	152,871	121
Totals	1,175,140	624,114	

*Current dollars

The 40% increase from the second to the third quarter of 1977 represents an annual increase of almost 300%. The increase from the annual total for 1976 to 1977 was about 90%. During the same period revenues increased only 50% and sales in kilowatt-hours <u>decreased</u> by 2%.

Table 1. Comparison of the Three Major California Public Utilities, 1976 and 1977

	PG&E			SCE			SDG&E		
	1977	1976	% Change	1977	1976	% Change	1977	1976	% Change
Service Area, sq. mi.	94,000	94,000		50,000	50,000		4,400	4,400	
Total Assets, 10^6\$	7,998	7,419	7.8	5,646	4,947	14.1	1,415	1,187	19.2
Equity as a % of Total Capitalization and Liabilities	48	45	6.7	45	47	(4.3)	41	41	
Investment in Electric Plant Facilities at original costs, 10^6\$	5,636	5,345	5.4	4,965	4,699	5.7	861	796	8.2
Electric Customers (x 10^3)	3,179	3,087	3.0	2,901	2,814	3.1	683	645	5.8
Sale of Electricity, MW-h	58,071	56,560	2.7	57,726	53,685	7.5	8,931	8,646	3.3
Capacity, MW	13,948	14,424	(3.3)*	14,337	14,066	1.9	2,273	2,278	(0.2)**
Peak Demand, MW	12,191	12,246	(0.4)	11,247	11,081	1.5	1,746	1,716	1.7
Average Price per kW-h(1), cents		2.58			3.52			3.64	
% of Generation Oil and Gas	72(2)	62(2)	16.1	78	77	1.3	87.6	79.3	10.5
Fuel and Purchased Power as a % of Operating Expenses(3)	68	63	7.9	68	59	15.3	63	61	3.3
% of kW-h to Industry	23	23		28.4	29.1	(2.4)	--(4)	--(4)	--(4)

*Due to adverse hydroelectric conditions
**Due to a reduction in firm contracts
Source: 1976 and 1977 Annual Reports for each company unless otherwise noted.

Notes:
1. Reference 28, page 64.
2. The figures for PG&E are for all thermal plants.
3. For PG&E and SDG&E, the Fuel and Purchased Power for both electric and gas sales are added and divided by the total operating expenses.
4. Data supplied by SDG&E does not separate industrial customers from the total for industrial and commercial. The California Energy Commission estimates that it is about 24%, but a look at SDG&E's industrial gas customers indicates that it might be about 20%.

The result of this change in generation mix (an additional 16 million barrels of low sulfur oil was burned in 1976 in comparison to 1975) has been a change in attitude toward alternative methods of generation. As stated in their 1978 annual report:

> "No single source of energy is the answer to our needs. All feasible sources must be developed and conservation must be vigorously pursued." (Reference 27, page 7.)

Such a change in attitude can only help industrial cogeneration. However, the rains experienced during the first quarter of 1978 could modify PG&E's new attitude as once again very inexpensive hydropower is purchased from outside the PG&E system or is generated at PG&E plants. By the end of the first quarter of 1978, 48.5% of PG&E's electric energy came from hydroelectric plants.*

Concerns About Cogeneration

PG&E is concerned about the influence of regulatory bodies on its activities. Of specific concern was the recent request by the PUC for guidelines and prices on the purchase of industrially cogenerated power. The utility felt that the publication of that information could hurt their negotiating position. PG&E wants to be able to negotiate with firms on an individual basis in order to keep the purchase price as low as possible. They fear that windfall profits for some cogenerators is a real possibility. Related to the problem of purchase price determination is PG&E's general concern about the type of projects that fall under PUC's classification of cogeneration. For instance, does the power that PG&E buys from the Dow Chemical Company - which is not cogenerating at this time - come under this classification? PG&E, as previously stated, is concerned only with the quality of the electricity, not in the fuel efficiency used by a second party to produce it.

As a result of the oil embargo and the drought, PG&E has become interested in all sources of power. However, PG&E and industrial firms do not always have identical interests. PG&E wants the flexibility to buy the least expensive power, which is hydro, when it is available. In addition to flexible prices, PG&E also prefers long-term contracts. Fifteen years is appropriate for its planning horizon. While some firms they are negotiating with have compatible planning horizons, other firms would like five year contracts. The firms prefer predetermined prices and demand requirements and arrangements that reflect fuel escalation rates. PG&E would prefer contracts that call for periodic price renegotiations. This arrangement would leave room for negotiation and it is PG&E's negotiating position that is their present concern. At this time, the entire pricing arrangement is subject to negotiation.

PG&E also questioned why a utility should pay for "waste" material, as in the case of wood waste (hog fuel) used in cogeneration. The proper determination of price of a fuel for which the owner must normally

*Personal communication, PG&E public information office, March 27, 1978.

pay to dispose, is a question that PG&E feels has not been adequately addressed. The question is, who gets the profit? PG&E would prefer that the reduced fuel price be passed on to them and their customers. They can see no rationale for tying the price of a waste material to the world price of oil as some firms have suggested.

II. SOUTHERN CALIFORNIA EDISON COMPANY

Of the three major California public utilities, SCE has the highest percentage of industrial customers. Their future fuel supplies appear to be assured and their financial status appears to be strong. Its biggest problem appears to be the continuing capital requirements of the San Onofre Nuclear Generating Station.

Although its energy costs are not increasing as rapidly as PG&E, SCE has incurred a 15% growth in energy costs from 1976 ($916,131,000) to 1977 ($1,040,091,000) with a comparable 13% increase in sales revenue. SCE generated 7.5% more electricity in 1977 through 1976. Thus its increased fuel costs were passed on to its ratepayers. Over the last decade, energy costs increased at an average annual rate of 26% while generation in kilowatt-hours increased at an annual rate of 4%. Due to air quality regulations, SCE must operate its plants in the South Coast Air Basin to minimize the NO_x emissions as opposed to minimizing the cost.

Concerns About Cogeneration

Mr. Edward Myers, a Vice-President of SCE, presented the company's optimistic and pessimistic viewpoints on cogeneration. On the optimistic side he stated that:

> "As energy costs continue to increase, industrial customers are becoming increasingly aware of the need to improve the energy efficiency of lifeline and time-of-use rates. The revenue deficiency caused by providing lifeline service is to be made up from primarily commercial and industrial classes of service. These subsidies, together with time-of-use rates, charging more for service used during a utility's peak period, will, on the surface, tend to make on-site generation look more promising. Thus, Edison expects an increase in the number of proposals for cogeneration ventures." (Reference 29, page 1591.)

On the pessimistic side, Mr. Myers expressed the utility's skepticism about cogeneration. The utilities insist that

(1) "...frequency control remain the province of the utility system, and

(2) "...that the system be adequately protected from undue outside influence."

They are concerned with the increasing complexity of system dispatch. In general, they realize the cogeneration potential is real,

> "...but that both the magnitude and impact of that potential have perhaps been overstated by on-site proponents in their explanation of cogeneration benefits." (Reference 29, page 1594.)

SCE is also concerned that industry will not be interested in industrial cogeneration because of the many institutional issues. The major issue is regulation: namely, the lack of a legal determination on how industrial cogenerators will be viewed by regulatory agencies. Will such generating facilities be viewed as part of the utility's generating system? If so, could they be forced to continue generating even if they find it to be uneconomic for the firm? These two questions remain to be adequately resolved. Until they are, cogeneration growth, as far as SCE is concerned, will not be significant.

III. SAN DIEGO GAS AND ELECTRIC

SDG&E is the smallest of the three public utilities examined in this study. Its service area is about 1/10 that of SCE and 1/20 that of PG&E, but its electrical sales are only about 1/6 that of SCE and slightly less than 1/6 of PG&E. About 80% of SDG&E's operating revenues are from electric service. Less than 0.2% of operating revenues are from steam sales.

The price of electricity from SDG&E is higher than that set by the other two utilities. Presently, it is about 3.5% higher than SCE and 4.1% higher than PG&E. Forecasts completed by the utilities show the difference in 1995 to be 25% higher than SCE and 60% higher than PG&E.* (Reference 28, page 641.)

Like other utilities, SDG&E has faced tremendous increases in fuel and purchased energy costs for electric generation. These costs have increased at an average annual rate of 29% over the past 10 years. Fuel and purchased energy costs for the generation of electricity as a percentage of total electric operating revenues has increased by almost a factor of three over the last 10 years, as is shown in Figure 1. SDG&E does not believe that this trend will continue as "the cost of power plant fuel oil rose more slowly (in 1976) than in either of the two previous years." (Reference 30, page 3.) However, in an effort to control these increases in fuel costs, SDG&E has consolidated all the "fuel procurement and development activities into a fuel resources department." (Reference 30, page 9.) Such an organizational change would help the company properly evaluate industrial cogenerated electricity. At this time, most of the efforts of this department have concentrated on the management of existing fuel and development of firm contracts for the future fuel supply.

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*If the California Energy Commission's estimates are used, SDG&E electricity will be 16% less expensive than SCE and only 20% higher than PG&E's price.

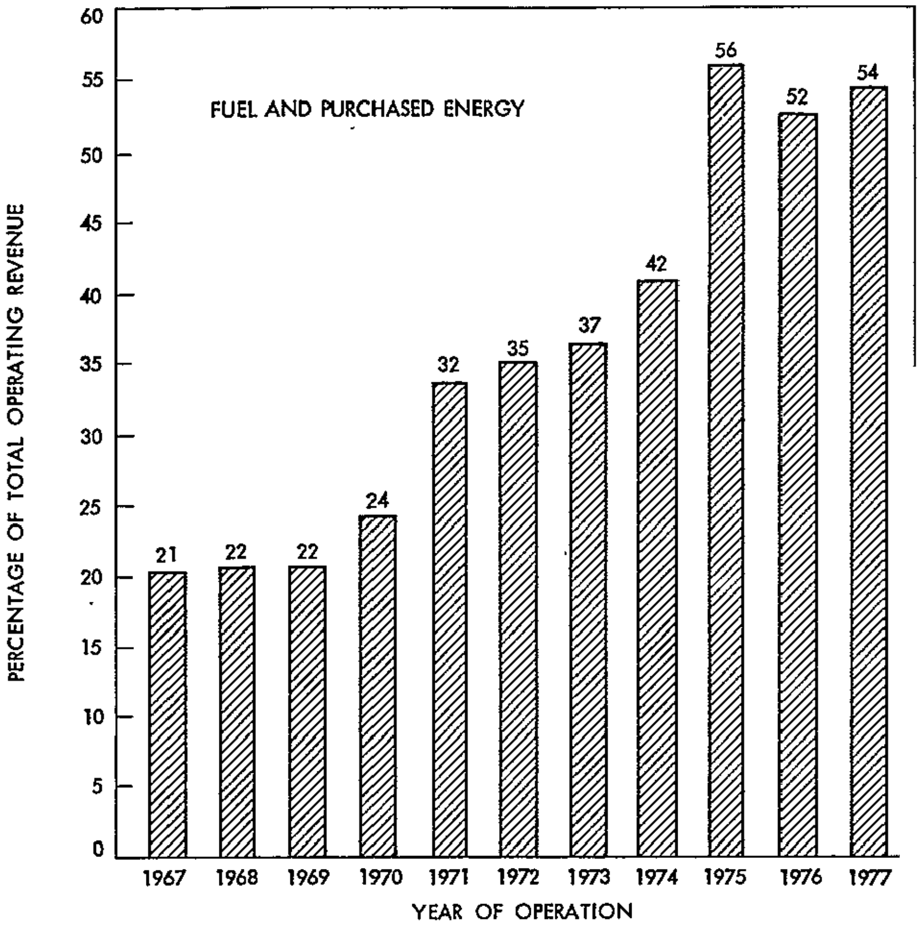

Figure 1. Fuel and Purchased Energy as a Percentage of Total Operating Revenue, San Diego Gas & Electric, 1967 to 1977

SDG&E established Applied Energy, Inc. (AEI), a wholly owned subsidiary, to handle all of its industrial cogeneration activities. AEI is not organized to handle the purchase of industrially generated power. Such arrangements must be coordinated with the parent company, SDG&E, if the industrial firm wants to own the generation equipment.

Concerns About Industrial Cogeneration

In general, AEI believes that private firms do not want to get involved in generating electricity. It does not perceive the cause for the lack of interest to be the fear of regulation, but rather that industrial cogeneration is viewed as another unwanted operations headache. In fact, it feels that many firms would like to get out of the steam generating business and concentrate on their own business. One reason for this observation could be the lack of large-energy industrial users in the SDG&E service area. As stated in the 1977 Annual Report:

> "While cogeneration is efficient, its contribution to system electrical requirements is expected to remain small because the number of industries that can use large amounts of steam is somewhat limited."
> (Reference 30, page 5.)

IV. COMPARISON OF THE PUBLIC UTILITIES

The preceding sections indicated the diversity of the three electric corporations regulated by the California Public Utilities Commission. Some of the important differences and similarities will be compared in this section.

Similarities

Some of the obvious similarities described in the previous section are:

(1) Energy costs and the ratio of energy costs to operating expenses have been increasing over the last decade.

(2) Substantial capacity expansion is planned.

(3) A feeling that each cogeneration project must be considered separately and that almost all necessary contractual matters are open to negotiation.

All of the utilities agreed that in the near term the amount of cogeneration that would be implemented would be too small to cause any changes in the reliability of their systems or in the reduction of their tariffs. However, they also agreed that there probably was a rate for introducing industrial cogeneration above which the utility could find itself having to charge higher prices for retail electricity. As one overview on cogeneration noted:

> "...it must be pointed out that with the increase of this type of system (industry operated cogeneration plant offsetting its electric demand) in any given utility area, a point may be reached in which the total utility load is predominantly of a residential and commercial type. Since these customers are relatively more expensive to service, the effect could be to increase the cost of electrical service." (Reference 1, page 38.)

Another similarity is the forecasted changes in reserve margin. The Congressional Office of Technology Assessment, in its review of the President's National Energy Plan, noted there were areas of concern that:

> "...could keep the Nation from realizing (industrial) cogeneration's full potential. Principally, utility interest in cogeneration will probably be very limited for the next several years because planned expansion of generating capacity will meet or exceed demand." (Reference 31, page 127.)

In California, electric utilities are required by Section 25300 of the Public Resource Code to include tabulations of reserve margins indicated by the 5, 10, and 20 year forecast of each utility's supply plan.* The table below summarizes the submissions by PG&E, SCE, and SDG&E.

Planned Reserve Margins

Year	PG&E	SCE	SDG&E
1976	23.9%	21.1%	23.1%
1977	25.3	24.3	17.8
1978	20.2	21.6	12.6
1979	16.5	18.9	22.1
1980	14.4	15.4	11.3
1985	15.4	15.7	11.8
1995	14.5	11.5	10.9

Note: Reserve margin is the percent net generating capacity in excess of annual peak demand. The national average in 1976 was 50% (Reference 13, page 15).

Source: California Energy Trends and Choices, (Reference 28, page 131).

Although the determination of the proper reserve margin is dependent on many factors, it can be seen that the three utilities are all planning to decrease the percentage. The accuracy of these forecasts is dependent on each utility's ability to bring planned capacity on-line and its ability to predict future demand. Nuclear power is a significant part of the planned capacity. Over the next 10 years, 38% of PG&E's capacity expansion and 47% of SCE's expansion will be from nuclear generating stations. SDG&E's capacity expansion was also heavily dependent on nuclear power. However, given the questions raised by the Public Utilities Commission and the California Energy Resources Conservation and Development Commission on nuclear power, it appears that the nuclear plants will not come on-line. The potentially shorter lead time for installing cogeneration could therefore become an important source of new capacity for SDG&E.

All three utilities have been involved in cogeneration projects in the past. However, only SDG&E has established a separate entity to look after cogeneration projects. Ironically, Applied Energy, Inc. was formed by the San Diego Gas and Electric Company to handle only one type of cogeneration arrangement--the sale of steam to industrial firms. At this point, they are awaiting the completion of their first civilian project with Rohr Industries, Inc., before other cogeneration projects are evaluated.

*Appendix E contains more detail on each utility's forecasting and plannin

Differences

Although the utilities realize that their planning environment is changing and that alternatives such as industrial cogeneration must be considered seriously, they differ in how they evaluate new cogeneration ventures. PG&E appears to be the most cautious. They have been reluctant to encourage cogeneration projects that cannot be considered as firm capacity. As a result, they are less inclined to want to incorporate cogeneration capacity into their resource planning. SCE appears to be less reluctant to incorporate cogeneration into their capacity supply planning. They have indicated that even cogeneration plants with random sales of excess electricity to the grid will be considered as part of the generating capacity, though not at its full capacity. For example, the Dow Chemical Co. contract with PG&E has a required capacity factor of 95%. In SCE's Alternate B, a 70% annual capacity factor is required. Because of the type of cogeneration projects entered into by SDG&E, the cogeneration capacity is considered as part of the utilities generating system.

As far as existing capacity goes, the availability of hydroelectric resources to PG&E is the most striking difference. This resource has obviously fluctuated in recent years, but its potential availability appears to make PG&E reluctant to consider contracts that might force them to buy relatively expensive cogenerated electricity when less expensive hydropower might be available.

All of the utilities are concerned about system control. However, here again there is variation. SCE, in its interruptible rate experiment, indicates that a premium is paid if the utility maintains control over the generating station's interface with the system. PG&E appears to want to consider only arrangements where it maintains control over the system interface. SCE, on the other hand, is considering the possibilities of some external control.

Each utility appears to have its own feelings on how the price of cogenerated energy should be evaluated and re-evaluated over time. SCE is willing to tie the price to either its average system cost (Alternate A) or its South Coast Basin oil and gas fired generation plant costs (Alternate B). SDG&E's price of waste heat sold to AEI for resale is directly tied to the cost of base load power. PG&E, however, prefers to negotiate each price separately and not tie it to other fuels. They feel it is their responsibility to get the best price for the electricity for their customers. For example, they question paying for wood waste as though it were equal to the dollar value of Btu equivalent oil, when in the past the seller has had to pay for disposing or treating the waste.

Finally, it is interesting to compare the opinions of the utilities as to why some firms might not be willing to consider cogeneration. All agreed that state and federal legislation clearly exempting industrial cogeneration from regulation was essential. Even a decision by the PUC was not considered sufficient. SDG&E felt that firms in its service area

would prefer not to have to worry about the production of steam let alone begin to consider operational responsibility for electric generation. SCE saw cost and availability of capital as the biggest obstacle to the firms as well as a fear that once they begin to cogenerate they might be forced to continue generation even if it is no longer profitable. PG&E felt that industrial concerns about future sources of fuel for cogeneration plants using a topping cycle was the dominant concern.

As a result of PUC resolution E-1738, it is probable that as each utility's guidelines on cogeneration are made public and as cogeneration arrangements come on-line and their performance is evaluated, the differences will decrease.

APPENDIX D

COGENERATION ACTIVITIES OF THE THREE MAJOR PUBLIC UTILITIES

I. PACIFIC GAS AND ELECTRIC COMPANY*

A. EXISTING COGENERATION PROJECTS

PG&E has three existing cogeneration** facilities that have been operating since the early 1940s. All three facilities involve refinery plants that trade fuel oil for steam from the PG&E owned and operated cogenerating plant. The arrangement was initially conducted under separate contractual agreements with each of the three refiners--Shell, Union, and Lion. Schedule No. P-8, Oil Refinery Electric and Steam Service, addresses the dollar value of the steam supplied. Special conditions under the schedule include a minimum 10 year contract. While the plants meet air quality standards, they are considered to be economically marginal by PG&E and are usually operated to meet the steam demands of the refineries. The agreement calls for 0.265 bbls of fuel oil and $2 for each 1,000 pounds of steam (160 psig) plus a demand charge of $6,000 per month.

PG&E has been buying electric power from other non-utility firms. One such arrangement is with the Dow Chemical Company in Pittsburg, California. The arrangement originally for six months, but recently renewed for another six months, calls for 15 MW of power at a 95% capacity factor. There is a severe penalty for any month in which the delivered power falls below this amount. Although the penalty should not pose a problem for Dow with its 300% reserve, it does reflect PG&E's concern about purchasing high quality (available and reliable) base load power.

Other arrangements where excess power is purchased by the utility exist with the Georgia-Pacific Corporation (1.2 MW), Louisiana Pacific Corporation (8 MW), and Stauffer Chemical Company (2 MW). All of these agreements are short term, although long term negotiations are underway for the first two firms.

PG&E will buy power at a price of 14 mills/kW-h because they have less expensive power available, depending on water conditions. For example, PG&E pays 3 mills/kW-h for dumped power from the Northwest and its variable cost for its own hydropower is nil. Any price above

*This section is based on a meeting with PG&E on January 17, 1978.

**In the past, PG&E defined cogeneration in its Commercial Guide as "joint electric generation projects where PG&E would own, operate and/or maintain some component of the power sources." Cogeneration arrangements without PG&E direct involvement were referred to as industrially produced power. Recently, this has been changed to include all facilities where there is "simultaneous production of useful heat in some form and electric energy in the same system."

14 mills per kW-h is subject to negotiation. PG&E is not concerned with how the electric power is generated. All of the power purchased from industry, whether or not it is cogenerated, is termed industrially generated power. PG&E has a standard contract form to purchase surplus energy up to 3 MW from industrial plants. Above 3 MW a case-by-case approach is followed where such issues as ownership, equipment purchase, land acquisition, and operating and maintenance responsibilities are negotiated.

PG&E contends that any capital investment they make should go into their rate base. For this reason, PG&E needs assurance that a cooperative venture will exist for a given period of time (six years at a minimum) so that they can continue to use it in their rate base calculations.

B. PRESENT ACTIVITIES

In late 1976, the California Public Utilities Commission (PUC) raised the matter of cogeneration potential in the state (Decision No. 85559). B. W. Shackelford, at that time a PG&E Senior Vice President for Planning and Research, presented in testimony to the PUC a list of 46 large gas consumers in the PG&E service area. These were considered to be energy users that should be considered for possible cogeneration projects. In early 1978, a team of eight people was formed to deal with cogeneration projects. In addition, several people in other departments are involved in evaluating and implementing cogeneration projects. Presently, PG&E is involved in 10 such projects, having a total estimated capacity of about 900 MW. These projects consist of:

(1) Enhanced oil recovery projects. Two projects--Getty and Texaco--have had feasibility studies conducted by an outside engineering firm. A definite decision on PG&E's involvement is expected by the end of 1978. A third project is with the Husky Oil refinery.

(2) Two waste heat recovery projects.

(3) Four wood by-product projects.

One of the wood by-product projects is with the Louisiana Pacific Corporation. Louisiana Pacific would use 2,100 tons of wood waste per day from a lumber mill in Oroville to fuel a turbine generator with a capacity of about 45 MW. (PG&E has estimated that as much as 635,000 barrels of oil equivalent per year could be saved with this project.) Louisiana Pacific asked PG&E to review the possibility of generating electricity from wood waste and residue. Following an initial evaluation, the two organizations hired a consultant for technical assistance in the area of wood gathering, storage, and combustion, as well as in planning the general layout of the plant.

The preliminary sizing considerations were based on the fuel availability. The wood wastes are categorized as sawdust, bark, and wood shavings. Wood chips were not considered in the original evaluation because they are already a marketable commodity. Although wood chips are not selling well at the present time, PG&E did not want to be forced to compete with others in the market for the wood chips. Like the Dow Chemical project, this example shows that PG&E is quite risk-averse in its purchase of industrially-generated electricity.

Although fuel availability was important in determining the size of the facility, the availability of a used turbine generator and two boilers determined the 45 MW capacity. The result is the production of 450,000 pounds/hour of steam, of which only 50,000 pounds/hour is required by Louisiana Pacific. Hopefully, the remaining steam can be utilized by other plants that might locate in the vicinity in the near future.

At this point the prices and other contractual arrangements have not been worked out. Points that remain to be resolved include:

(1) Ownership.

(2) Operation responsibility.

(3) Price for waste wood.

(4) Cost of steam to industry.

II. SOUTHERN CALIFORNIA EDISON COMPANY

A. EXISTING COGENERATION PROJECTS

SCE has two existing cogeneration agreements, one with the Garden State Paper Company (15 MW) and another with the Stauffer Chemical Company (4 MW). The Garden State Generating Station, in Pomona, is owned and operated by SCE. Steam is sold under a negotiated contract to the Garden State Paper Company. Electricity is still purchased from the SCE system. Operations began in 1966.

The Garden State cogeneration facility developed as a result of the competition between electric and gas utilities in the mid-1960s. SCE examined about 40 industrial customers where cogeneration arrangements could be established in order to keep SCE customers from switching to natural gas. Only one facility--the Garden State Paper Company--was considered to be a beneficial investment for the utility.

B. PRESENT COGENERATION ACTIVITIES*

As a result of California Public Utilities Commission Decision No. 85559, SCE began to search for potential cogeneration projects. In late 1977, SCE expanded its cogeneration team in order to increase its efforts in attracting industrial cogenerators. The SCE effort to implement industrial cogeneration involves three engineers, one marketing representative, and several field representatives. As of February 1978, no contracts had been signed.

As a first step toward implementing cogeneration, SCE established three alternatives utilizing on-site cogeneration. Experimental tariffs for interruptible service and parallel generation were also established. The three schemes are:

Alternate A - Partial Requirements

Alternate B - Resource Type

Alternate C - Utility Ownership

Alternate A is much further along in terms of contractual review and development. Position papers on Alternates B and C have not been completely reviewed by SCE or any potential customers. The three alternates are discussed below.

Alternate A

Most of the industrial interest in cogeneration in the SCE service area has been directed toward Alternate A, in which the customer plans to replace all or a portion of his present energy source--SCE--while keeping SCE as back-up. SCE has established a policy paper in the form of a contract to facilitate beginning negotiations. Counteroffers, including changes to the present price structure for the sale of electricity to the utility, will be considered, especially if the customer presents its specific objections and recommendations. The proposed price for excess electricity would be based on the total system average cost. As with time-of-use (TOU) rates, the price would depend on when it is made available to the grid.

An important feature of Alternate A is the way that back-up power or standby charges are handled. Prior to this pricing scheme, if a firm required standby power, its charge was \$2/kW for the first 20 kW and \$1.50 for all excess kW on standby. In addition there was the regular demand charge plus a 50% carry over of the demand charges based on the highest maximum demand established in the previous 11 months. Under Alternate A, these charges would be eliminated and only the actual demand charge and an 85% ratchet would be employed. The 85% ratchet refers to the setting of a monthly minimum demand charge based on the highest demand over the past 11 months. The example in Table 1 shows a savings of \$412 over a five-month period. An actual example cited by

*This section is based on a meeting with SCE on March 7, 1978.

Table 1. Comparison of SCE's Alternate A to SCE's Regular Standby Tariff

Month	kW Demanded[1] (Peak)	Alternate A	Regular Standby Tariff: Demand Charge	Standby Charge	Ratchet (50%)	Total
1	50	$105.00[2]	$105[2]	$85[4]	$52	$242
2	10	89.25[3]	21	85	52	158
3	10	89.25	21	85	52	158
4	10	89.25	21	85	52	158
5	10	89.25	21	85	52	158
	Totals:	$462.00				$874

(1) This is the assumed kW actually demanded in each month. 50 kW is assumed to be the maximum over the previous 11 months. Only peak demand is analyzed here.

(2) kW x $2.10/kW on peak demand. This rate is from TOU-8 schedule.

(3) 85% ratchet - ($105 x 0.85 = $89.25) - applied to maximum demand over the past 11 months if higher than present month.

(4) 50 kW is assumed to be on standby. The charge is based on $2.00 for the first 20 kW and $1.50 for each additional kW on standby.

SCE would result in a monthly savings of $62,000 or 86% under Alternate A. Basically what happens is that the responsibility for insuring adequate back-up is accepted by SCE.

More important from the standpoint of future capital expenditures is whether or not SCE would count the on-site generating equipment in its resource planning. If SCE does not, and the total potential demand of the customer remains on the demand side of the resource plans, the result would be an increase in the capital expenditure per kilowatt. This follows because both the utility and the firm are investing in capacity. SCE stated that their system planning department has indicated that cogeneration will be counted in SCE's capacity planning. Each site, depending on its characteristics, will be assigned a factor by which its capacity will be multiplied to determine an effective planning capacity. Because none of the contracts for Alternate A have

been signed, no factors have been defined. All special contracts, such as Alternate A, must be reviewed by the PUC. In the past, SCE has had no difficulty in having special contracts approved. The PUC appears to have the attitude that the contract must be satisfactory if the customer and utility both feel that it is beneficial. However, PUC review of existing contracts can occur at any time and could result in contractual changes in the price or other aspects of the agreement.

Alternate B

Under Alternate B, the generating facility is owned by the customer, but all or a portion of it is considered as part of SCE's firm power. The draft contract that SCE is developing requires a 70% annual capacity factor and an 85% annual on-peak capacity factor for the contracted capacity to ensure that it is dependable power. In addition, the contract would be in force for 10 years and renewable in five year increments. (SCE's planning cycle is five years.)

There are three parts to the payment by SCE for this firm power:

(1) Energy Credit - SCE will pay up to 85% of the South Basin oil- and gas-fired generation costs. Presently this cost is about 19.3 mills/kW-h, but it can fluctuate every quarter. Because the power is considered as part of the utility's firm power, there is no differentiation between power delivered on or off peak.

(2) Capacity Credit - If a firm that is already a customer installs a cogeneration capability, the capacity is not of value to SCE for five years. The value of the capacity is discounted to reflect this fact. If a new customer comes on line with a cogeneration capability, the capacity is immediately of full value. The capacity value has not yet been completely worked out by SCE.

(3) Operation and Maintenance Credit.

Although one customer is interested in Alternate B, no customers have reviewed the proposed contract to date. One reason might be that there are few firms that have the required steam loads or that can meet the continuous operating cycle requirements.

Alternate C

Under Alternate C, the utility owns the generating facility. This arrangement is similar to that for the Garden State Paper Company facility described previously. This type of arrangement is more appealing to SCE because of the control they maintain over the generating equipment. The major obstacle for the utility is the lack of capital. However, the availability of capital for cogeneration is an obstacle for either the utility or the firm under all three alternatives.

III. SAN DIEGO GAS AND ELECTRIC CORPORATION*

A. EXISTING COGENERATION PROJECTS

SDG&E's view of cogeneration as described in a recent article, appears to be quite different than PG&E or SCE:

> "San Diego Gas and Electric favors the concept of utility-owned and operated cogeneration plants located on or next to customer premises - where it can sell the waste heat and keep the electricity - rather than become involved with customer-owned facilities.
>
> "In keeping with this philosophy, the utility has set up a subsidiary company, Applied Energy, Inc., to concentrate exclusively on working out cogeneration arrangements with industrial customers and to help them evaluate their needs and options."
> (Reference 22, page 241.)

Applied Energy, Inc. (AEI) was incorporated in 1968 to handle the supplying of steam to the U. S. Naval Training Center and the Marine Corps Recruiting Depot. Three steam-producing facilities employing cogeneration technology owned by SDG&E are not operated by AEI. It is important to remember that AEI is involved only in the "manufacturing" of steam and its sale. All of the equipment used to generate electricity is owned and operated by SDG&E. The exhaust heat from the SDG&E turbines is "purchased" by AEI which in turn uses it to manufacture the required steam. The steam is used by the customer for processing and space heating. Because of the steam supply orientation, each of the three facilities is overdesigned to ensure that the customer's steam demand is met. Whether the steam is supplied by the waste heat boilers connected to the turbines or by a separate package boiler is an economic decision based on the quantity of steam required and the type of fuel available. If necessary, the electricity is produced at a very low efficiency or not at all.

The first Naval facility, with a capacity of 15 MW, was contracted for in 1968 and came on line in 1971. The second (20 MW) and the third (20 MW) came on line in 1976 and 1978, respectively.

SDG&E established AEI to streamline the legal involvements and to keep all the attendant contractual and administrative problems in a separate profit center. This arrangement is similar to the establishment of separate R&D and operating subsidiaries by some utilities. The PUC is interested in what AEI does, but it does not have the same direct operating jurisdiction over AEI activities as it does over SDG&E.

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*This section is mostly based on a meeting with SDG&E/AEI representatives on January 23, 1978.

AEI has kept a very low profile while servicing a limited market. Considering that it has been in existence for 10 years, there is very little public information concerning its activities. In 1973, there was a brief article on its chilled water supply systems (Reference 6, page 8) and in 1977 an article appeared on a planned cogeneration facility (Reference 22, page 24). AEI is also investigating installing a turbine from which waste heat would be derived for use in absorption chillers at its chilled-water facility.

B. PRESENT ACTIVITIES

AEI is a small company with four full-time personnel and two temporary personnel; two allocated positions have not yet been filled. During periods of construction and operation, AEI hires personnel from SDG&E on a contract basis. Billing and expenses for 1977 amounted to $6 million, with those for 1978 projected at $10 million. About 90% of their revenue is derived from the three steam contracts noted above. The fuel costs for 1978 are projected to total $16 million. However, they will obtain an electricity credit of about $9 million from SDG&E. Nineteen seventy-seven was not a good year because of turbine operating problems: the turbine breakdown at one facility resulted in the production of costly steam by a package boiler. The use of a package boiler is not economic, but, as mentioned previously, is legally required by the existing contracts for steam.

AEI can be described as a steam contractor. The steam billing to a customer is determined by the amount of steam used. It is the responsibility of AEI to supply the steam continuously. The cost of steam from a cogeneration system is determined by first establishing the cost of the exhaust heat. To calculate that cost, the amount of gas and oil used per month is calculated than multiplied by current prices to obtain a total equivalent fuel cost for the operation of the turbines. Next, the electricity meter is read to determine the electricity produced. (AEI has little control over how much electricity is used by SDG&E. The load management control belongs to SDG&E.) A credit for this electricity is then calculated. The $/kW-h was not given, but it is based on the cost of base load power. This credit is subtracted from the fuel cost to derive a dollar value for the exhaust heat as shown below:

$$\text{Value for Exhaust Heat} = \text{Cost of Fuel to Operate Turbines} - \text{Credit for Electricity Generated}$$

This amount is divided by the pounds of steam sold to get a fuel cost for steam to AEI. The fuel cost comprises 70% to 80% of the steam cost. The rate structure (based on a declining block schedule) is predetermined in contracts with the company that buys the steam.

In summary, AEI is organized to maximize their return on sale of steam and not to produce electricity at minimum cost. Thus, the parent company pays a price for its electricity equivalent to other sources. This is the opposite of the concept used in many studies that look at the marginal cost for producing on-site electricity and selling the steam at slightly below existing costs.

Recently, AEI has been looking into establishing more steam contracts with private customers. The company has established a contractual agreement with Rohr Industries to place an 800 kW on-site cogeneration plant for the supply of 7,000 lb/hr, 15 psig, 250°F saturated steam. Although other industries have expressed interest, AEI wants to complete the Rohr agreement before it examines other potential sites. AEI has identified about 26 other potential customers, some of whom could be combined into joint projects.

Presently the Rohr arrangements are progressing smoothly and will be an excellent test case. In March 1977, the original contact was made by Rohr with AEI and by September the contract agreement was signed. In February 1978, the last permit was acquired by AEI. AEI has a 20-year contract consisting of two 10-year terms with Rohr. There will probably be an escalation clause in all contracts that will be tied to the Engineering News Record Construction Index.

APPENDIX E

ELECTRICITY FORECASTING AND PLANNING BY THE THREE MAJOR PUBLIC UTILITIES

I. PACIFIC GAS AND ELECTRIC COMPANY

In its February 1977 submission to the California Energy Commission, PG&E forecasted a 4.6% annual growth rate for the sale of electricity as shown in Table 1. The peak capacity was forecasted to grow at 4.2%. The percentage of industrial sales remains constant at about 25% of the total kW hrs sold.

Table 1. Electricity Forecasts by Pacific Gas and Electric Company

Year	Sales, 10^6 kW-h		
	Total	Industrial	Peak Capacity, MW
1975	60,262	15,428	12,983
1980	80,941	20,994	16,601
1985	100,866	25,961	20,430
1990	122,364	31,416	24,503
1995	148,983	37,851	29,799
Percent Growth Rate			
1975-85	5.3	5.3	4.6
1975-95	4.6	4.6	4.2

Note: Data supplied by PG&E to the California Energy Resources Conservation and Development Commission in Feburary 1977.

Source: Reference 28, pages 37, 38, 30.

The California Energy Commission has reduced these forecasts by about 20% for sales and about 15% for capacity. The reasons given for the modification are:

(1) Different assumptions about future energy prices.

(2) Non-price conservation adjustments in the commercial and industrial sectors.

(3) Different residential sales forecasting methodology and different assumptions. (Reference 28, page 34.)

II. SOUTHERN CALIFORNIA EDISON COMPANY

In the January 1977 submission to the California Energy Commission SCE forecasted a 4.3% annual growth rate for the sale of electricity as shown in Table 2. Peak capacity was forecasted to grow at 3.2%. In comparison to PG&E and SDG&E, SCE is forecasting the lowest growth rate. In addition, SCE is the only utility forecasting a decrease in the percentage of sales to industrial customers.

Table 2. Electricity Forecasts by Southern California Edison Company

Year	Sales, 10^6 kW-h		Peak Capacity, MW
	Total	Industrial	
1975	50,108	17,336 (35%)[1]	10,193
1980	59,676	18,676 (31%)	12,510
1985	75,171	21,705 (29%)	15,470
1990	94,345	26,702 (28%)	19,400
1995	116,402	32,609 (28%)	23,740
Percentage Growth Rate			
1975-85	4.1	2.3%	4.3[2]
1975-95	4.3	3.2%	4.3[2]

Note: Data supplied by SCE to the California Energy Resources Conservation and Development Commission in August 1976 and January 1977.

Source: Reference 28, pages 61, 62, 63.

(1) Industrial sales as a percentage of total sales. Note that this is higher than shown in Table 1 in Appendix C for 1976 and 1977.

(2) Corrected from 4.5% listed in source.

SCE's forecasts were modified by the California Energy Resources Conservation and Development Commission (CERCDC) to reduce total sales by about 10% and to increase the percentage of sales to industrial customers over the SCE forecasts. The percentage of industrial sales still declines over the next 20 years under CERCDC's adopted forecast, but only by two percentage points. Reasons for the changes made in the SCE forecast include adjustments for the following factors:

(1) Reduction of SCE's upward adjustment in sales due to the implementation of lifeline rates. SCE had assumed that lifeline rates would cause an increase in demand.

(2) Non-price conservation in the residential sector.

(3) SCE's high projections for non-residential forecasts based on lower projections of electricity prices (Reference 28, page 56).

III. SAN DIEGO GAS AND ELECTRIC COMPANY

In the January 1977 submission to the CERCDC, SDG&E forecasted a 5.8% annual growth rate for the sale of electricity as shown in Table 3. No changes were made by the CERCDC. The peak capacity was forecasted to grow at 5.8%. These estimates show SDG&E is the fastest growing major electric utility in the state. Such growth at a time when the cost of construction of power plants is so high has been cited at the major reason for the company's financial problems. Its stock (common and preferred) are both rated below PG&E and SCE, and its bonds are now rated at BBB, the lowest rating given "investment grade" securities (References 32 and 33).

Table 3. Electricity Forecast by San Diego Gas and Electric Company

Year	Sales, 10^6 kW-h		Peak Capacity, MW
	Total	Industrial	
1975	8,141	1,980 (24%)[1]	1,619
1980	10,785	2,790 (26%)	2,234
1985	14,500	3,977 (27%)	3,006
1990	19,571	5,597 (29%)	3,971
1995	25,091	7,276 (29%)	4,985
Percent Growth Rate			
1975-85	5.9	7.2	6.4
1975-95	5.8	6.7	5.8

Note: Data supplied by SDG&E to the California Energy Resources Conservation and Development Commission in January 1977.

Source: Reference 28, pages 54, 55.

(1) Industrial as a percentage of total sales.

APPENDIX F

MUNICIPAL UTILITIES

I. WHAT IS A MUNICIPAL UTILITY?

The joint undertaking by the City of Santa Clara and the California Paperboard Corporation was viewed as one of the most promising of the cogeneration projects examined in this study. A major reason for this favorable assessment was related to the characteristics of a municipal utility. One study concluded that:

> "...municipal utilities are more likely to be the first to adopt innovative, large-scale cogeneration than are large, investor-owned electric utilities. Municipals are more closely tied to local community needs and are better able to respond to their needs because they are less regulated than investor-owned utilities; many already sell steam or are empowered by their charters to do so; and they are generally permitted to site plants closer to load areas than large, investor-owned plants." (Reference 34, page 19.)

Before looking at some of the characteristics of a municipal utility, it is important to examine the legal status of a municipal utility as described in the Public Utilities Code. In Paragraph 10002, the code states that

> "Any municipal corporation may acquire, construct, own, operate or lease any public utility."

In addition, under Paragraph 10004, the municipal government

> "...may sell, lease or distribute the excess (water, light, heat or power) outside of its corporate limits."

These powers appear to be quite broad, but there are some notable exceptions that need further examination. For instance, there is no mention of the PUC aiding or supporting the municipal government in carrying out those powers. More important are the implications of Paragraph 10107, the effect of Article 3 on powers of the PUC and the Department of Public Works:

> "Nothing in this article limits in any respect the jurisdiction powers, and duties vested by law in the PUC...shall prevail."

Though Article 3 deals with Rights of Way, the broad language of the paragraph suggests wider implications.

While it is commonly held that utilities owned by municipal governments are not regulated by the PUC, there is no statement in the code that limits the PUC's jurisdiction. However, under the Municipal Utility District Act (Division 6 of the Public Utilities Code) the Directors of the District have the power and duty to supervise and regulate the fixing of rates, contracts, practices, schedules, and other aspects of the utility district. In fact, the powers of this type of a municipal utility are left unconstrainted by Paragraph 11884 on Administrative Powers:

> "All matters and things necessary for the proper administration of the affairs of the district which are not provided for in this division (6) shall be provided by the board (of directors)."

As early as 1956 these powers were interpreted by the courts as giving one utility district the ability to increase its revenues to meet any increase in costs by increasing its rates or by levy of taxes (Sacramento Municipal Utility District vs. Spriles, 1956, 303 P2d 40, 145 C.A. 2d 561). Only recently has the PUC provided the public utilities with an abbreviated hearing process (Energy Cost Adjustment Clause) to cover the increasing cost of fuel without a rate hearing. (Decision No. 87531, April 27, 1976.)

Division 7 is almost a mirror image to Division 6, except that it is designed to establish and empower public utility districts, i.e., "municipal" utility districts in an unincorporated area. This provision allows the people of that area to obtain the advantages of having certain utilities.

In summary, we see that there are at least four ways a local government can be involved in supplying a public service:

(1) Granting a franchise to a utility.

(2) Owning a utility.

(3) Having a municipal utility district in its jurisdiction.

(4) Having a public utility district in its jurisdiction.

II. CHARACTERISTICS OF MUNICIPAL UTILITIES WITH RESPECT TO COGENERATION

Municipal utilities are considered to be prime institutions to implement cogeneration because:

(1) Municipals are not directly regulated by state or federal public utility agencies.* In addition, they have access to low cost municipal loans and taxes on the generation facility are less.

*The California Energy Resources Conservation and Development Commission does have power plant siting authority over municipal utilities.

(2) Municipal utilities face an uncertain future about the source of their electricity and its cost.

Most of the municipal utilities* are only distribution systems that buy electricity from larger generation and transmission systems. These larger systems are often owned by investor-owned public utilities such as PG&E and SCE. The municipals charge that they:

> "...are having to bear a heavier share of rate increases than large companies served by investor-owned utilities under retail contracts. As a result of this discrimination, the cities say, they are losing their ability to compete for industry. And some are even coming under pressure to sell city-owned utilities that have helped support sagging municipal budgets." (Reference 35.)

The investor-owned utilities

> "...deny the price gap is their fault or that they are trying to squeeze the cities' utilities out of business. Rather, they say the differences are due to the fact that wholesale power rates are set by federal regulators, while retail rates are fixed by state commissioners." (Reference 35.)

One investor-owned utility in Florida was charged by the Federal Power Commission with "anticompetitive" conduct by refusing to sell bulk power to cities, and by denying them use of its transmission lines to buy cheaper power elsewhere. The utilities say the accusations are "without foundation." However, as a result of the higher bill they have paid, the municipal's customers have voted to have the investor-owned utility take over the municipal system. (Reference 35.)

Given the above characteristics, it would appear that the municipal utilities would be inclined to install their own generating facilities. The first characteristic implies that municipally-owned generating plants can produce less expensive energy for their customers. In addition, municipals do not usually make a profit on their operation, thus creating more of a gap between the cost of investor-owned generation and municipally-owned generation. The second characteristic implies that the municipal electric utilities face an uncertainty over price and availability of the traditional sources of electricity. Ownership of generation facilities is one method for reducing this uncertainty and at the same time reducing the price of electricity for the municipal's customer. Cogeneration plants with their reduced capital expenditures, generating costs, and emissions in comparison to traditional fossil-fuel generating plants should prove to be appealing.

*Los Angeles Department of Water and Power is a notable exception.

III. MUNICIPAL UTILITIES' OUTLOOK ON COGENERATION*

Based on the discussion above, one would expect to see increased activity in cogeneration by the municipal utilities. At this time, however, the opposite appears to hold true in California. The Northern California Power Association (NCPA) was established by 11 municipal utilities to develop generation projects. Most of their efforts have been devoted to two geothermal projects in Northern California. However, none of the municipal utilities, with the exception of the City of Santa Clara, were actively developing cogeneration projects. Many municipal utilities view cogeneration as a problem and not as an opportunity; instead of the economics and operating benefits noted above, they see:

(1) Legal negotiations.

(2) The need to acquire new operating personnel.

(3) Difficulties in obtaining permits.

(4) Concerns about whether the industrial firm will stay in business.

As noted, the City of Santa Clara is the exception. Their work to date has concentrated on acquiring all the permits and in negotiating contracts in order to establish a cogeneration facility at the California Paperboard Corporation plant. The facility would be owned by the City. Other firms have already come to the City to request similar arrangements. The City is now having talks with the California Energy Resources Conservation and Development Commission regarding their assistance in establishing an effective energy audit that will identify the best cogeneration candidates. The City appears to be ready and willing to proceed with more utility-owned cogeneration systems. However, they plan to wait until the California Paperboard project is operating before they will consider other sites.

IV. COMPARISON TO THE PUBLIC UTILITY OUTLOOK

At this time it appears that the municipals are not moving as fast as the public utilities which are motivated by the Public Utilities Commission. This situation could soon reverse itself as more municipals and their industrial customers see the results, if successful, of the pioneering cogeneration projects.

*This section is based on a meeting with the City of Santa Clara Electric Department on January 18, 1978.

APPENDIX G

SOUTHERN CALIFORNIA AIR POLLUTION CONTROL DISTRICT
NEW SOURCE REVIEW RULES

RULE 213 Standards for Permit to Construct: Air Quality Impact

RULE 213.1 Standards for Permit to Operate: Air Quality Impact

RULE 213.2 Definitions for Rules 213 and 213.1

Adopted October 8, 1976 by the Air Resources Board to be effective immediately and to apply to any subject application filed with the District, but not finally acted upon prior to October 8, 1976

RULE 213. Standards for Permits to Construct: Air Quality Impact

(a) General

The Air Pollution Control Officer shall deny a permit to construct for any unit or units of a stationary source that fail to meet the applicable requirements of subsection (b) or (c) of this Rule.

(b) Best Available Control Technology

New Stationary Sources:

The Air Pollution Control Office shall deny a permit to construct for any unit or units constituting a new stationary source if such source will emit more than 15 pounds per hour or 150 pounds per day of nitrogen oxides, organic gases, or any contaminant for which there is a state or natural ambient air quality standard (except carbon monoxide, for which the limits are 150 pounds per hour and 1500 pounds per day) unless the applicant shows that the new source is constructed using best available control technology.

2. Modification to Existing Stationary Sources:

The Air Pollution Control Officer shall deny a permit to construct for any modification of any existing stationary source if such source after modification will emit more than 15 pounds per hour or more than 150 pounds per day of nitrogen oxides, organic gases, or any air contaminant for which there is a state or national ambient air quality standard (except carbon monoxide, for which the limits are 150 pounds per hour and 1500 pounds per day), unless the applicant demonstrates that the modification of the existing stationary

source will be constructed using best available control technology, and:

A. That the modification would not result in a net increase in emissions of any pollutant affected by this Rule; or

B. That best available control technology is being, or is to be, applied to all existing units of the stationary source; or

C. That emissions from all of the existing units of the stationary source are controlled by use of technology that is at least as effective as that generally in use on similar stationary sources, and that the cost of installing best available control technology on existing units is economically prohibitive and substantially exceeds the cost per unit mass of controlling emissions of each pollutant through all other control measures; or

D. That the stationary source is a small business, as defined in subsection (1) of Section 1896 of Title 2 of the California Administrative Code; that emissions from all existing units of the stationary source are controlled through application of the best technology that is economically reasonable to apply to that stationary source; and that the cost of employing best available control technology is economically prohibitive.

(c) Air Quality Impact Analysis

1. New Stationary Sources:

The Air Pollution Control Officer shall deny a permit to construct for any unit or units constituting a new stationary source if such source will emit more than 25 pounds per hour or 250 pounds per day of nitrogen oxides, organic gases, or any air contaminant for which there is a state or national ambient air quality standard (except carbon monoxide, for which the limits are 250 pounds per hour and 2500 pounds per day), or which is a precursor of any such air contaminant, unless he determines that the emissions from the new source will not cause a violation of, or will not interfere with the attainment or maintenance of, the state or national ambient air quality standard for that same contaminant (or, in the case of a precursor, for the contaminant to which the precursor contributes).

2. Modifications to Existing Stationary Sources:

The Air Pollution Control Officer shall deny a permit to construct for any modification of any existing stationary

source if the modification will result in a net increase in emissions from the existing source of more than 25 pounds per hour or 250 pounds per day of nitrogen oxides, organic gases, or any air contaminant for which there is a state or national ambient air quality standard (except carbon monoxide, for which the limits are 250 pounds per hour and 2500 pounds per day), or which is a precursor of any such air contaminant, unless he determines that the emissions from the modified source will not cause a violation of, or will not interfere with the attainment or maintenance of, the state or national ambient air quality standard for that same contaminant (or, in the case of a precursor, for that contaminant to which the precursor contributes).

(d) Determination of Emission Increases

In determining under subsection (b) 2. A. and subsection (c) 2. whether there has been a net increase in emissions and, if so, the amount of any such increase, the Air Pollution Control Officer shall consider all increases and decreases of emissions caused by modifications to that stationary source pursuant to permits to construct issued during the preceding five years, or since the adoption of this Rule, whichever period is shorter. Emission reductions required to comply with federal, state, or district laws, emission limitations, or rules or regulations shall not be considered to be decreases in emissions for the purposes of this subsection.

(e) Consideration of Future Emission Reductions

In making the analysis required in subsection (h) 2., the Air Pollution Control Officer shall take into consideration the air quality impact of any reduction in the emissions of the same air contaminant which results from the elimination or modification of other existing stationary sources under the same ownership and operating within the same air basin. If reductions are to be based on planned elimination or modification of any stationary sources, the Air Pollution Control Officer shall condition the permit to operate to require such elimination or modification within not more than 90 days after the start-up of the new or modified source. Emission reductions required to comply with federal, state, or district laws, emission limitations, or rules or regulations shall not be considered to be decreases in emissions for the purposes of this subsection.

(f) Exemptions

1. The Air Pollution Control Officer shall exempt from the provisions of subsection (c) of this Rule, any new stationary source or modification of any existing stationary source which:

   A. Will be in whole or in part a replacement for an existing stationary source at the same location if

the resulting emissions of any air contaminant will not be increased. The Air Pollution Control Officer may allow a maximum of 90 days as a start-up period for simultaneous operation of the existing stationary source or replaced portions thereof, and the new stationary source or replacement; or

B. Will cause demonstrable air quality benefits within the air basin, provided however, that the written concurrence of the California Air Resources Board and United States Environmental Protection Agency shall be obtained prior to the granting of an exemption hereunder; or

C. Will be used exclusively for providing essential public services such as schools, hospitals, or police and fire fighting facilities, but specifically excluding sources of electrical power generation other than for emergency standby use at essential public service facilities; or

D. Is exclusively a modification to convert from use of gaseous fuels, provided that all units constituting the modification will utilize best available control technology. Modifications for the purpose of this paragraph shall include the addition or modification of facilities for storing, transferring and/or transporting such fuel oil at the stationary sources. A condition shall be placed on the operating permit requiring conversion to gaseous or other equivalent low polluting fuels when they are, or become, available; or

E. Is air pollution control equipment which, when in operation, will reduce emissions from an existing source; or

F. Is portable sandblasting equipment used on a temporary basis within the air basin.

2. The Air Pollution Control Officer may exempt from the provisions of subsection (c) of this Rule, any new stationary source, or modification of an existing stationary source, which has been determined to be:

A. A new stationary source or modification of an existing stationary source utilizing unique and innovative control technology which will result in a significantly lower emission rate from the stationary source than would have occurred with the use of previously known best available control technology, and which will likely serve as a model for technology, to be applied to similar stationary sources within the State. In

order for a stationary source to be exempted under this paragraph, the applicant must obtain the written concurrence of the California Air Resources Board and the United States Environmental Protection Agency with the Air Pollution Control Officer's determination; or

B. A new stationary source or modification of an existing stationary source that represents a significant advance in the development of a technology that appears to offer extraordinary environmental or public health benefits or other benefits of overriding importance to the public health or welfare. In order for a stationary source to be exempted under this paragraph, the applicant must obtain the written concurrence of the California Air Resources Board and the United States Environmental Protection Agency with the Air Pollution Control Officer's determination.

(g) Notice Requirements for Proposed Exemptions

Before granting an exemption under subsection (f) 1. B., (f) 2. A. or (f) 2. B. of this Rule, the Air Pollution Control Officer shall publish a notice by prominent advertisement in at least one newspaper of general circulation in the District and shall notify in writing of his intention: the applicant, the United States Environmental Protection Agency, the California Air Resources Board and adjoining air pollution control districts. Calculations and technical data used by the Air Pollution Control Officer as the bases for granting exemptions pursuant to subsection (f) 1. B., (f) 2. A. or (f) 2. B. shall be made available to the California Air Resources Board and United States Environmental Protection Agency. Before granting an exemption under subsection (f) 1. B., (f) 2. A. or (f) 2. B. of this Rule, the Air Pollution Control Officer shall consider any comments received within 30 days after the date of publication or date of notification of the above agencies, whichever occurs later, and shall have obtained the concurrence of the California Air Resources Board and the United States Environmental Protection Agency.

In addition, the Air Pollution Control Officer shall notify in writing the United States Environmental Protection Agency and the California Air Resources Board of the granting of an exemption under subsection (f) 1. A., (f) 1. C. or (f) 1. D.

(h) Procedures for Evaluation of Applications for Permits to Construct:

Before granting a permit to construct for any unit of a new stationary source or modification subject to the requirements of subsection (c) of this Rule, the Air Pollution Control Officer shall:

1. Require the applicant to submit information sufficient to describe the nature and amounts of emissions, location,

design, construction, and operation of the source, and to submit any additional information required by the Air Pollution Control Officer to make the analysis required by this Rule.

2. Analyze the effect of the operation of the new or modified stationary source on air quality in the vicinity of the new source or modified stationary source, within the air basin and within adjoining air basins. Such analysis shall consider the air contaminant emissions and air quality in the vicinity of the new source or modified source, within the air basin and within adjoining air basins at the time the new source or modification is proposed to commence normal operation. Such analysis shall be based on the application of existing state and local rules and regulations.

3. Upon completion of the evaluation, but before granting a permit to construct:

   A. Publish a notice by prominent advertisement in at least one newspaper of general circulation in the District, stating the preliminary decision to grant the permit to construct and where the public may inspect the information required by this subsection. A copy of the notice shall also be sent to the applicant, the United States Environmental Protection Agency, the California Air Resources Board and adjoining air pollution control districts. The notice shall provide a period of 30 days, beginning on the date of publication, or on the date of notification of the above agencies, whichever occurs later for the public to submit comments on the application.

   B. Make available for public inspection at the Air Pollution Control District office, except as otherwise limited by law: the information submitted by the applicant, the Air Pollution Control Officer's analysis of the effect of the source on air quality, and the preliminary decision to grant the permit to construct. Such information shall also be forwarded to the California Air Resources Board for review.

   C. Consider all comments submitted. If within the 30-day notice period the Air Pollution Control Officer receives a written request from either the United States Environmental Protection Agency or California Air Resources Board to defer the Air Pollution Control Officer's decision pending the requesting agency's review of the application, the Air Pollution Control Officer shall honor such request for a period of 60 days from the date of such request.

(i) Additional Applicant Requirements

Receipt of a permit to construct shall not relieve the stationary source owner or operator of the responsibility to comply with other applicable portions of the District's Rules and Regulations.

(j) Severability

If any portion of this Rule shall be found to be unenforceable, such finding shall have no effect on the enforceability of the remaining portions of the Rule, which shall continue to be in full force and effect.

RULE 213.1. Standards for Permits to Operate: Air Quality Impact

(a) Requirement for Permit to Construct as Condition for Permit to Operate

The Air Pollution Control Officer shall deny a permit to operate for any stationary source subject to the requirements of Rule 213 unless the applicant has obtained a permit to construct.

(b) Air Quality Impact Analysis for Sources Emitting Larger Quantities of Air Contaminants Than Assumed in the Analysis Performed Pursuant to Rule 213

The Air Pollution Control Officer shall not grant a permit to operate to any stationary source that he determines emits quantities of air contaminants larger than were assumed in the analysis performed for the permit to construct for the source, unless the Air Pollution Control Officer performs the air quality impact analysis required by Rule 213 and determines that the actual emissions from the source will not cause a violation of, or will not interfere with the attainment or maintenance of, any state or national ambient air quality standard.

(c) Permit Conditions

The Air Pollution Control Officer shall condition the issuance of a permit to operate, on such terms as are deemed necessary to ensure that the stationary source will be operated in the manner assumed in making the analysis required by Rule 213 or subsection (b) of this Rule, whichever is applicable. Where appropriate, such conditions shall prohibit a new stationary source which is a replacement for an existing stationary source from operating, unless the operation of the existing source is terminated. The Air Pollution Control Officer may allow a maximum of 90 days as a start-up period for simultaneous operation of the existing stationary source or replaced portion thereof, and the new stationary source or replacement portions thereof.

(d) Exemptions

The Air Pollution Control Officer shall exempt from the provisions of this Rule, any stationary source which:

1. Has received a permit to construct prior to the adoption of Rule 213.

2. Is a continuing operation, without modification, of a stationary source that was previously exempt from the permit provisions of these Rules and Regulations and a permit to operate is required solely because of a change in permit exemptions stated in Rule 219.

(e) Severability

If any portion of this Rule shall be found to be unenforceable, such finding shall have no effect on the enforceability of the remaining portions of the Rule, which shall continue to be in full force and effect.

RULE 213.2. Definitions for Rules 213 and 213.1

(a) STATIONARY SOURCE means a unit or an aggregation of units of non-vehicular air-contaminant-emitting equipment which is located on one property or on contiguous properties; which is under the same ownership or entitlement to use and operate; and, in the case of an aggregation of units, those units which are related to one another. Units shall be deemed related to one another if the operation of one is dependent upon, or affects the operation of, the other; if their operation involves a common or similar raw material, product, or function; or if they have the same first three digits in their standard industrial classification codes as determined from the <u>Standard Industrial Classification Manual</u> published in 1972 by the Executive Office of the President, Office of Management and Budget.

In addition, in cases where all or part of a stationary source is a facility used to load cargo onto or unload cargo from cargo carriers, other than motor vehicles, the Air Pollution Control Officer shall consider such carriers to be parts of the stationary source. Accordingly, all emissions from such carriers (excluding motor vehicles) which will result in an adverse impact on air quality in the State of California shall be considered as emission from such stationary source. Emissions from such carriers shall include those that result from the operation of the carriers' engines; the purging or other method of venting of vapors; and from the loading, unloading, storage, processing, and transfer of cargo.

(b) MODIFICATION means any physical change in, or any change in the method of operation of, a stationary source.

For the purposes of this definition:

1. Routine maintenance or repair shall not be considered to be a change in the method of operation, provided that these increases are not contrary to any existing permit to operate conditions.

(c) BEST AVAILABLE CONTROL TECHNOLOGY means the maximum degree of emission control for any air contaminant emitting equipment, taking into account technology which is known but not necessarily in use, provided that the Air Pollution Control Officer shall not interpret best available control technology to include a requirement which will result in the closing and elimination of or inability to construct a lawful business which could be operated with the application of the best control technology currently in use.

(d) Severability

If any portion of this Rule shall be found to be unenforceable, such finding shall have no effect on the enforceability of the remaining portions of the Rule, which shall continue to be in full force and effect.

APPENDIX H

AIR QUALITY REGULATORY CONSTRAINTS FOR COGENERATION IN CALIFORNIA

Regulatory constraints on air quality may take the form of specific emission standards or criteria by which identified environmental impacts are to be mitigated. Attaining certain levels of air quality in some localities may add more general constraints and also may include specific prohibitions. The following sections explore air quality regulatory constraints on implementation of cogeneration faciliites in California.

I. CLEAN AIR ACT

The Air Quality Act of 1967 (Reference 36) attempted to establish a balance between state and federal air pollution control responsibilities. The federal government was directed to establish air quality control regions (air shed basins) and to publish appropriate air quality criteria for each region. The states were directed to adopt ambient air quality standards set by federal or state governments and to adopt implementation plans to achieve the standards. The 1967 Act approach was not entirely successful and was modified in 1970.

The passage of the Clean Air Act Amendments (CAA) of 1970 (Reference 37) was a significant step forward in federal air pollution control; these amendments are the foundation for current air pollution control programs.

Even though state and local agencies retained the responsibility for controlling air pollution in their regions, the CAA of 1970 gave the federal government much stronger legal tools to deal with air pollution. These included the responsibility and authority to enforce state and local air pollution control programs, to enforce pollution controls, and even to assume the duties of the state or local agencies should they fail in their mandated responsibilities.

Some of the more important provisions of the CAA of 1970 are included in sections 108 through 112 of that legislation. Section 108 requires that air quality criteria be developed for the major air pollutants which may have a potentially adverse impact on public health and welfare. Section 109 requires National Ambient Air Quality Standards (NAAQS) to be established based upon the air quality criteria developed according to the requirements of section 108. Implementation plans for achieving and maintaining the NAAQS are required of each state according to section 110. Finally, section 111 requires that "Standards of Performance" be developed for new and modified stationary sources of pollution. These standards constitute direct emission limitations for pollutants from a number of specified types of sources, including fossil-fuel-fired steam generators and stationary gas turbines. Section 112 of the CAA of 1970 requires establishment of national emission standards for hazardous air pollutants (NESHAPS).

On August 7, 1977, President Carter signed P.L. 95-95, the Clean Air Act Amendments of 1977 (Reference 38). These Amendments impose a wide range of new responsibilities upon the operators of stationary source facilities and substantially change the conditions for obtaining permits for new and expanded plants. Compliance with the Amendments will require development, interpretation, and submission of several kinds of technical data and will generally increase the lead time required for obtaining permits to construct.

Some of the more important provisions of the CAA of 1977 are included in sections 160 through 178 of that legislation. Sections 160 through 169, "Prevention of Significant Deterioration (PSD) of Air Quality," was added to establish three land classifications for allowable increases of total suspended particulates (TSP) and SO_2 (sulfur dioxide) in areas where air quality is now cleaner than required by ambient air quality standards. Sections 171 through 178 deal with plan requirements for non-attainment areas, areas which now exceed NAAQS.

II. JURISDICTION OF ENVIRONMENTAL AGENCIES

As the principal federal agency for environmental matters, the Environmental Protection Agency (EPA) has primary responsibility for the implementation of the Clean Air Act and its Amendments. The EPA has set criteria in accordance with section 108, has established national ambient air quality standards (NAAQS) in accordance with section 109, and retains ultimate authority to implement them. States are allowed to set stricter, but not weaker, standards than the federal requirements. States must have a state implementation plan (SIP) detailing how it will attain clean air standards.

In California, each of the forty-seven air pollution control districts is required to submit to the California Air Resources Board plans for meeting state and federal air standards within their jurisdiction. The collection of air district programs forms the basis for the state plan, which also includes a statewide plan for controlling mobile pollution sources.

The state can specify regulations for an air district, or revise the district's plan if it is considered inadequate. The EPA has final review and approval authority over the state plan. California's implementation plan is currently under revision because the EPA judged inadequate that part of the procedures for meeting air quality standards. It should be noted that there are practical limitations to the EPA's authority. The EPA cannot force a state to implement a specific program if the latter chooses not to do so. The EPA may itself implement such a program, but would probably find the administrative requirements prohibitive in terms of costs and personnel.

In accordance with the Clean Air Act Amendments of 1970, the EPA required each state to submit a state implementation plan (SIP) within nine months after the NAAQS were issued. The first deadline was 1975, and has since been delayed twice. First, the EPA granted California and

other states an extension until June 30, 1977. California, like many other states, did not meet clean air standards in 1977, so in the 1977 amendments to the Clean Air Act Congress granted another extension until 1982; for areas with severe oxidant or carbon monoxide problems the extension may be delayed until 1987. The recent federal amendments also require states to submit new implementation plans by 1978 detailing how air quality standards will be met.

The New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD), and New Source Review (NSR) regulations are three important programs currently administered by the EPA which are relevant to implementation of cogeneration facilities. The standards of performance for new stationary sources are enforced by the local Air Pollution Control Districts (APCD) in California according to guidelines set forth by the EPA. The Air Conservation Program (ACP), currently under development by the California Air Resources Board (ARB), is in response to the federal PSD program. Model rules for New Source Review have been established by the ARB and are intended for adoption by the local APCDs. To date less than half of the APCDs have adopted the suggested NSR rules. These programs are described in the following sections.

III. NEW SOURCE PERFORMANCE STANDARDS

Section 111 of the Clean Air Act Amendments of 1970 authorizes the EPA to impose emission standards on those stationary sources that are determined to be significant contributors to air pollution and that consequently endanger the public health or welfare. Section 112 of the Act authorizes the EPA to promulgate national emission standards for hazardous air pollutants (NESHAPS). The EPA's use of Section 111 and 112 authority provides a quick-response emission control program compared to the relatively slow process of establishing additional ambient air quality standards and having the states adopt implementation plans (section 109). The Clean Air Act Amendments of 1977 have further broadened and strengthened the EPA's direct regulatory authority. Section 111 (a) (1) defines standard of performance to mean "a standard for emission of air pollutants which reflects the degree of emission limitation achievable through the application of the best system emission reduction 'BACT' which, taking into account the cost of achieving such reduction, the Administrator determines has been adequately demonstrated." In determining the degree of emission limitation achievable, which has been adequately demonstrated for purposes of promulgation of clean air standards, the Administrator of EPA is entitled to make a projection based on existing technology. That projection is subject to the restraint of reasonableness and cannot be based on "crystal ball" inquiry. An "adequately demonstrated" system is one that has been shown to be reasonably reliable, reasonably efficient, and that can be expected to serve the interests of pollution control without becoming exorbitantly costly. An achievable standard is one that is within the realm of an adequately demonstrated system's efficiency, and one that, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within industry prior to its adoption (Reference 39).

A. NEW SOURCE PERFORMANCE STANDARDS FOR EQUIPMENT USED IN COGENERATION SYSTEMS

Pursuant to section 111 of the Federal Clean Air Act, the Administrator of the EPA had promulgated standards of performance for a number of new or modified stationary sources, including fossil-fuel-fired steam generators (Reference 40). The standards are applicable to fossil-fuel-fired boilers of more than 250 million Btu per hour of heat input which are, or have been, constructed or modified after August 17, 1971. Included under the NSPS are emission standards for SO_2 (sulfur dioxide), NO_x (oxides of nitrogen), and particulate and visible emissions (Table 1). Pursuant to the same section of the Clean Air Act, EPA has recently (October 3, 1977) proposed standards of performance for stationary gas turbines (Reference 41) of more than 10.7 gigajoules (10.13 million Btu) per hour heat input. Included under these NSPS are emissions standards for SO_2 and NO_x (Table 2). Requirements for performance by the operator and installation of continuous emission monitoring equipment are also a part of these standards.

B. ADMINISTRATION AND ENFORCEMENT OF NSPS

The state may seek EPA approval to enforce NSPS for applicable stationary sources within their boundaries. To facilitate state participation, the EPA has established guidelines identifying the administrative procedures the state should adopt for implementation and enforcement of the NSPS (Reference 42). In California, the EPA has delegated enforcement authority for NSPS and NESHAPS to the state Air Resources Board (ARB) which has in turn delegated this authority to the local Air Pollution Control Districts (APCD). A number of APCDs in California have adopted the NSPS for some cogeneration equipment such as fossil-fuel-fired steam generators and have been granted EPA approval for their enforcement. Other districts also are planning to adopt NSPS.

IV. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

On May 24, 1972, the Sierra Club, the Metropolitan Washington Coalition for Clean Air, and the New Mexico Citizens for Clean Air and Water filed suit against EPA Administrator Ruckelshaus in U.S. District Court, District of Columbia, for a declaratory judgment and injunctive relief against EPA regulations which permit significant deterioration of air quality in pristine areas. This action led to the development of EPA's Prevention of Significant Deterioration (PSD) regulations in 1974 (Reference 43) and 1975 (Reference 44), and which are now in effect in California.

The EPA's PSD regulations (40 CFR 52.21) require the states to protect air quality superior to National Secondary Ambient Air Quality Standards (ambient air quality standards for protecting public welfare) for total suspended particulates and sulfur dioxide. The regulations identify three classes of clean air areas: Class I, very little deterioration; Class II, moderate deterioration; Class III, up to secondary

Table 1. Summary of New Source Performance Standards for Fossil-Fuel-Fired Steam Generators Over 250 Million Btu Per Hour (Reference 40)

Pollutant	Standard	Fuel
Particulates	0.10 $lb/10^6$ Btu heat input	Gas, oil, coal
SO_2	0.8 $lb/10^6$ Btu heat input	Oil
SO_2	1.2 $lb/10^6$ Btu heat input	Coal
NO_x	0.2 $lb/10^6$ Btu heat input	Gas
NO_x	0.3 $lb/10^6$ Btu heat input	Oil
NO_x	0.7 $lb/10^6$ Btu heat input	Coal
Opacity	20 percent	Gas, oil, coal

Table 2. Summary of Proposed New Source Performance Standards for Stationary Gas Turbines Over 10.13 Million Btu per Hour Heat Input (Reference 41)

Pollutant	Standard	Fuel
NO_x*	75 PPMV at 15% oxygen	Natural gas and distillate fuel oil
SO_2	150 PPMV at 15% oxygen corresponds to a fuel sulfur content of 0.8 percent by weight	Natural gas and distillate fuel oil

*It has been assumed that distillate fuel oil and natural gas contain no "fuel-bound" or "organic" nitrogen.

Table 3. Specific Limitations of Each Class of Clean Air Areas (Reference 43)

Pollutant	Class I $\mu g/m^3$	Class II $\mu g/m^3$	Class III
Particulate matter			
Annual geometric mean	5	10	Deterioration up to ambient air quality standards is permitted
24-hour maximum*	10	30	
Sulfur dioxide			
Annual geometric mean	2	15	
24-hour maximum*	5	100	
3-hour maximum*	25	100	

*For the purposes of these regulations, the second highest concentration measured is considered the maximum allowable.

standards. Each class reflects different social, economic, and environmental needs. Specific limitations of each class are presented in Table 3.

A provision in the EPA regulations allows the states to develop their own plans to prevent significant deterioration of air quality with the stipulation that these plans must be at least as stringent as the EPA program and be approved by the EPA. The California Air Resources Board developed its Air Conservation Program (ACP) to protect present superior air quality in certain areas, to identify areas needing restoration of superior air quality, and to permit necessary development in other areas (Reference 45). The intent of the ACP was not only to fulfill the requirements of the EPA's "no significant deterioration" regulations, but also to adapt the federal mandate to meet California's needs by including all pollutants for which state or federal standards exist and by establishing clean air policies for all areas of the state. Presently ACP is being revised to fulfill new requirements imposed by the Clean Air Act Amendments of 1977.

Under the old ACP, all areas of the state would be placed in one of four classes, ranging from areas where very little deterioration of air quality above existing levels would be permitted to areas where quality would not be allowed to exceed State and National Ambient Air Quality Standards. In Class A areas, no significant deterioration areas, very little if any air quality deterioration would be allowed, while in Class B areas, minimum deterioration areas, some deterioration would be allowed, but air quality better than the existing standards would be maintained. In Class C areas, agriculture/silviculture areas, air

quality sufficient to protect agricultural and silvicultural productivity would be the goal. In Class D areas, urban-industrial areas, achievement and maintenance of the existing state and federal standards would be sought.

The map in Figure 1, prepared by ARB staff, indicates how various areas in California could eventually be classified based on current land use. Final classification was expected in early 1978, but has now been postponed due to ongoing revision of the ACP.

A. IMPLEMENTATION POLICIES: REVIEW OF NEW SOURCES

The policies to implement the ACP are not well defined at this time. Examination of alternatives and selection of appropriate policies are in progress. Under Plan Development for the old ACP (Reference 45) the policies below were considered for reviewing of new sources in Class A areas.

(1) Policy 1: Prevention of Emission Increases from Air Pollution Sources Located Within Class A Areas. Under this policy new sources of emissions would be permitted in Class A areas only if there are emissions reductions of a corresponding magnitude from existing sources.

(2) Policy 2: Prevention of Significant Deterioration of Ambient Air Quality Levels. This policy would prohibit the deterioration of ambient air quality levels beyond certain very small deterioration increments. Emissions from sources inside Class A areas and from sources outside the Class A areas would be considered in this part of the ACP.

Under these two policies, new sources inside Class A areas would have to meet both policy criteria: (1) no increase in area wide emissions and (2) no significant deterioration of air quality greater than the allowable increment. Significant sources located sufficiently close to Class A areas to have an impact would be reviewed only under the second policy.

B. IMPLEMENTATION MECHANISM

The mechanism to implement ACP is not well defined at this time. Under the old Plan Development for ACP (Reference 45), the following mechanism was proposed: For Class A areas the permit authority of the Air Pollution Control Districts would be the principal tool to implement the program. Reviews of proposed air pollution sources or source expansion inside or outside of Class A areas would be made to determine the impacts of source emissions on ambient air quality, and to determine whether an area's emission limitation might be exceeded.

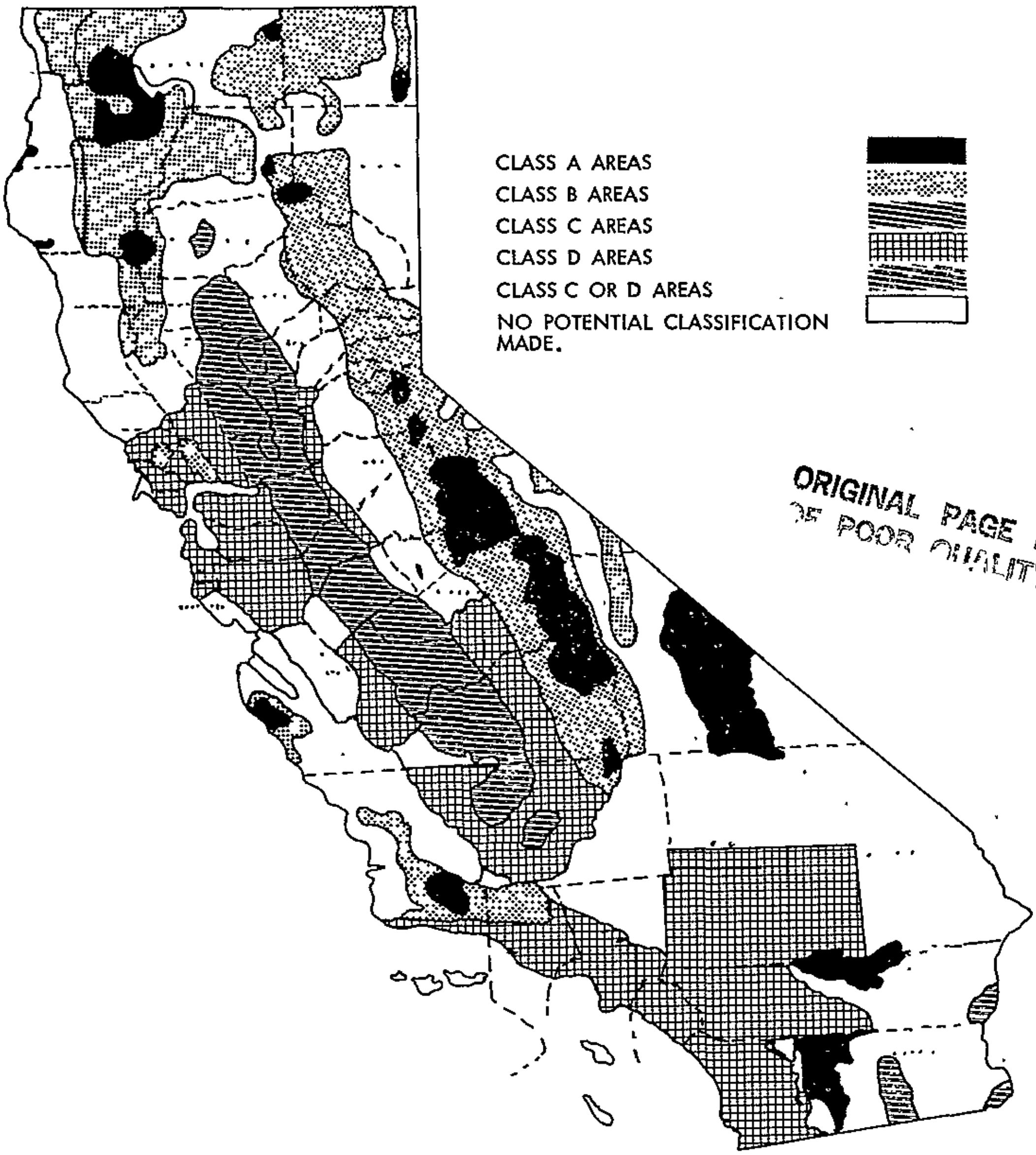

Figure 1. Potential Classification (Reference 45) of California Under the Air Conservation Program

C. RECENT DEVELOPMENT ON PREVENTION OF SIGNIFICANT DETERIORATION

The 1977 amendments essentially ratify, extend, and generally make more stringent the prevention of significant deterioration provisions promulgated by the EPA in December 1974. The provisions require that the maximum increases in SO_2 and TSP concentrations throughout these regions not exceed the specified increment of the related NAAQS concentrations for these pollutants. The three classes of clean air areas and their allowable air quality increment limitations established in the 1977 amendments are shown in Table 4.

Facilities commencing construction after August 7, 1977, in the PSD area or the area with impact on the PSD area, will be reviewed according to the PSD requirements of the 1977 amendments. However, for these facilities the EPA PSD regulations remain in effect until state implementation plans (SIP) are revised to incorporate the PSD requirements of the 1977 amendments. States are required to complete appropriate SIP revisions by December 1, 1978.

The EPA is also required to promulgate PSD regulations governing carbon monoxide, hydrocarbons, oxides of nitrogen, and photochemical oxidants by August 1979.

Table 4. Specific Limitations of Each Class of Clean Air Areas (Reference 38)

Pollutant	Class I $\mu g/m^3$	Class II $\mu g/m^3$	Class III $\mu g/m^3$	NAAQS $\mu g/m^3$
SO_2				
Annual	2	20	40	80
24-hour*	5	91	182	365
3-hour*	25	512	700	1300(S)
Particulate Matter				
Annual	5	19	37	75(P) and 60(S)
24-hour*	10	37	75	260(P) and 150(S)

*All 24-hour and 3-hour values may be exceeded once per year.

(S) indicates a secondary standard.
(P) indicates a primary standard.

V. NON-ATTAINMENT REGIONS

A non-attainment (NA) region is one which exceeds National Ambient Air Quality Standards (NAAQS) for at least one of the criteria pollutants (photochemicals, oxidants, CO, NO_2, SO_2, particulates, and hydrocarbons). Both state and federal laws require that the government agencies responsible for controlling air pollution formulate programs which will permit air quality standards to be achieved and maintained. A number of these standards are exceeded in many parts of California, often by substantial amounts (see Figure 2). Thus, any implementation plan for complying with the ambient air quality standards in California must deal with the problem of uncontrolled growth of emission sources in such areas which would create serious air quality problems even if the best available emission control technologies were utilized.

The Clean Air Act Amendments of 1970 explicitly recognized that emissions limitations alone are not sufficient in non-attainment areas to attain and maintain ambient air quality standards. In formulating its basic guidelines for the content of state implementation plans in 1971, the EPA determined in 40 CFR 51.18 that "other measures necessary to insure" achievement and maintenance of the ambient air quality standards can be provided by a New Source Review (NSR) regulation. 40 CFR 51.12(b) requires state regulations to subject new air pollution sources to preconstruction review, and to prohibit the construction of a new or modified stationary source which would interfere with the attainment or maintenance of the air quality standards.

When the California State Implementation Plan was submitted to EPA in 1972, no APCD rules and regulations contained NSR provisions. Consequently, the EPA formally disapproved the NSR portion of the SIP and, in 1973, promulgated Federal NSR regulations to be implemented by the EPA as required by the Clean Air Act.

Subsequent to EPA actions, all the APCDs in California adopted NSR rules to supplement existing permit systems. However, upon review by the EPA, less than a quarter of all the APCDs were given EPA approval. The EPA continued its own NSR program for those districts which failed to meet federal requirements.

The California Air Resources Board (ARB) has determined that the APCD's NSR programs not only fail to meet federal requirements, but also fail to satisfy the state's Public Health and Safety Code. In an effort to satisfy both federal and state requirements and to return NSR to local authority, the ARB has drafted suggested NSR regulations (model NSR) intended for implementation by the local districts. The EPA has indicated that it will discontinue its NSR program and leave NSR to the state and the local districts when APCDs adopt and implement NSR regulations similar to those proposed by ARB.

The implications of NSR led to the concept of emission offset or air quality trade-offs. The EPA said that allowing additional industries to locate in an area whose air was already dirtier than federal standards (non-attainment area) would be a violation of the Clean Air

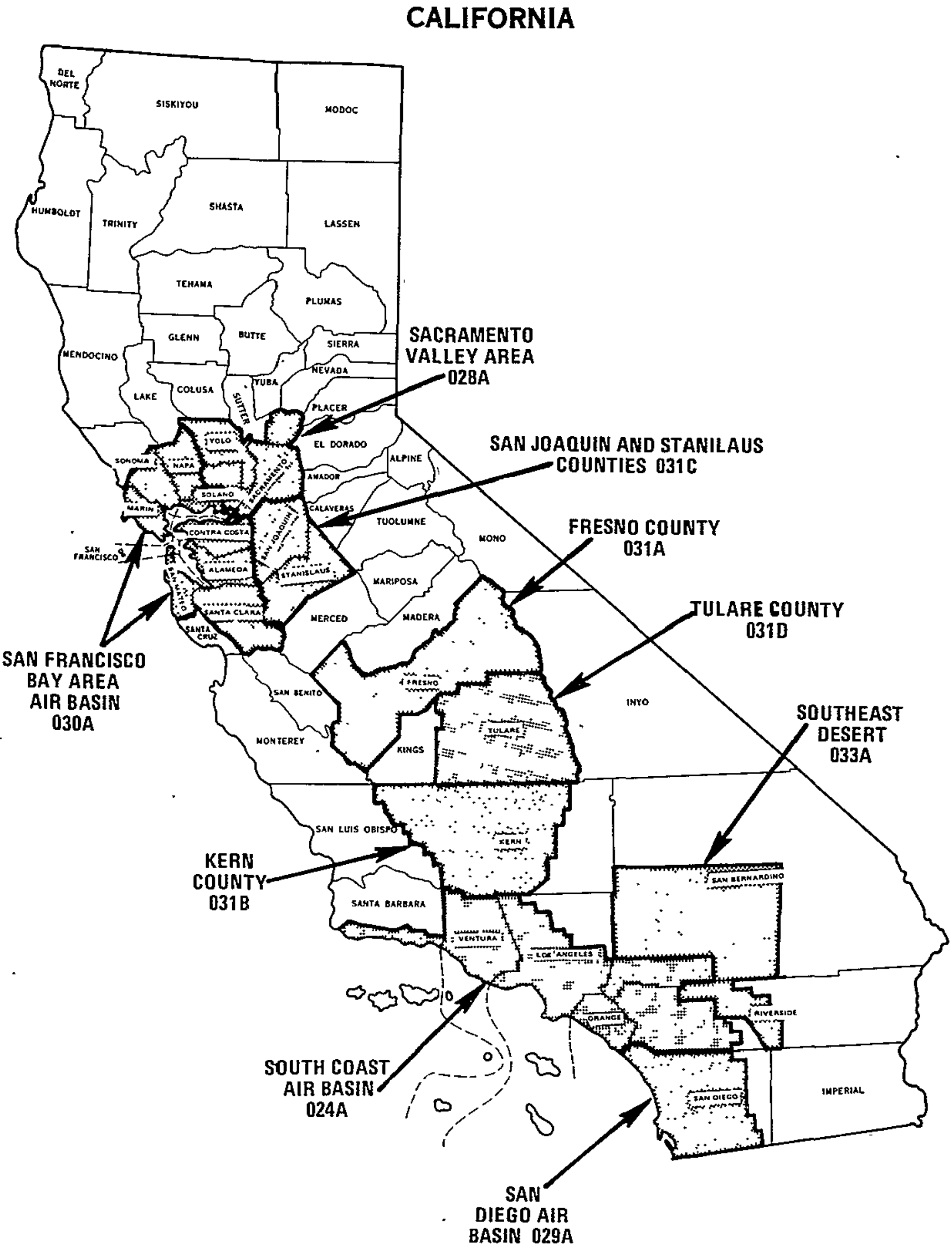

Figure 2. Air Quality Maintenance Areas in California (Reference 45)

Act. However, many labor and business groups opposed the policy of refusing to allow further development in regions violating air standards, calling it a "no growth" measure.

The Clean Air Act did not specify how this conflict might be resolved. At the end of 1976, EPA interpreted the act to allow the establishment of an air trade-off policy (Reference 46). Meanwhile in California, the ARB adopted NSR regulations for the South Coast Air Quality Management District (see Appendix G). These regulations were interpreted to mean that air trade-offs between different companies would be permitted.

Under provisions of the Clean Air Act Amendments of 1977 the existing EPA emission offset policy remains in effect until July 1, 1979. After July 1, 1979, states must revise their SIPs to assure that non-attainment areas will meet national ambient air quality standards for all pollutants by December 31, 1982, or by December 1987, for photochemical oxidants or CO if the 1982 date cannot be met using all reasonably available measures (Reference 36). The SIP revisions must specify the amount of new source growth which will be permitted; new sources must achieve the lowest achievable emission rate (LAER) (Reference 36). LAER is defined as the most stringent emission limitation which is contained in the SIP of any state for such source, or the most stringent emission limitation which is achieved in practice, whichever is more stringent.

A. MODEL FOR NEW SOURCE REVIEW

The New Source Review (NSR) rules adopted by the Air Resources Board for the South Coast Air Quality Management District (SCAQMD) are discussed here as a model for NSR Rules. It should be noted that NSR for other APCDs are slightly different.

Basically, the NSR rules provide a decision tree for determining whether or not to permit the construction or modification of a stationary source such as cogeneration facilities. This section will discuss the basic steps in the decision tree shown in Figure 3. Further definitions and interpretations for NSR rules are provided later. The first step in this decision tree is to meet all applicable NSPS and local prohibitory rules. The second step is to fulfill requirements under NSR rules. The major requirements for a new or modified stationary source under the NSR rules are as follows:

(1) Using Best Available Control Technology (BACT) in all equipment for controlling those pollutants whose uncontrolled emission rates are more than 15 pounds per hour or 150 pounds per day (except carbon monoxide, for which the limits are 150 pounds per hour or 1500 pounds per day).

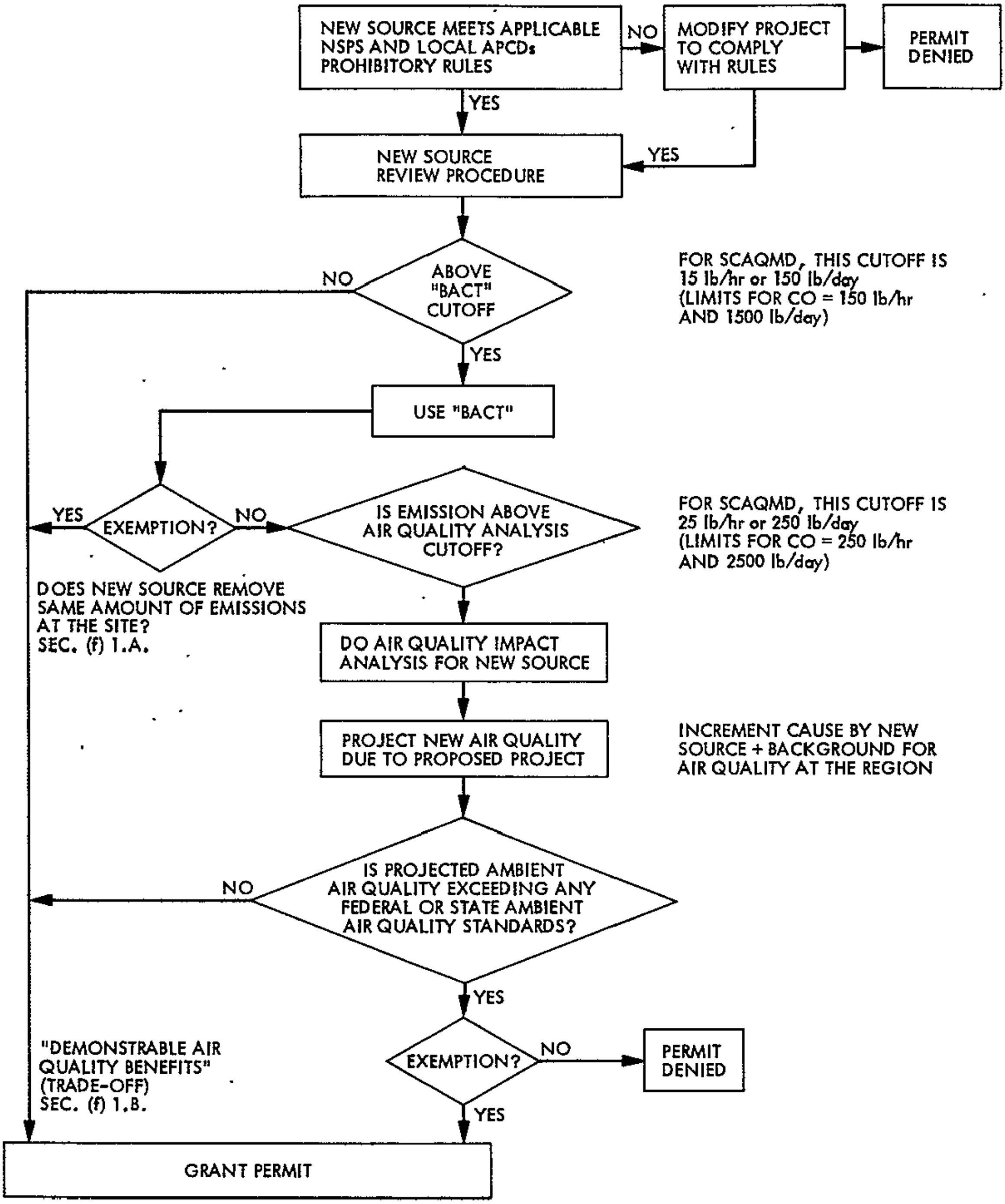

Figure 3. New Source Review (NSR) Procedure Flow Chart Applicable to Cogeneration Facilities in California (Based on Rule 213 of South Coast Air Quality Management District)

(2) Requiring air quality impact analysis for the source if, after applying BACT, the emission rates for any pollutants are more than 25 pounds per hour or 250 pounds per day (except carbon monoxide, for which the limits are 250 pounds per hour or 2500 pounds per day). In this case the permit to construct will be denied unless air quality analysis demonstrates that the emissions from the new source will not cause a violation of or, in the case of a non-attainment area, will not interfere with the attainment or maintenance of any state or national ambient air quality standards. Exemptions to the above requirement are as follows:

(a) A new or modified stationary source that in whole or in part is a replacement for an existing stationary source on the same property if the resulting emission of any pollutants will not be increased (section (f) 1.A of Rule 213).

(b) A new or modified stationary source which can prove demonstrable air quality benefits within the air basin, provided however, that the written approval of the ARB and the EPA shall be obtained prior to the granting of an exemption hereunder (section (f) 1.B. of Rule 213).

B. DEFINITIONS AND INTERPRETATION OF NEW SOURCE REVIEW RULES

Definitions for some of the terms in New Source Review Rules are as follows:

(1) POLLUTANTS - any air contaminant for which there is a state or national ambient air quality standard. In the case of proposed cogeneration systems, these pollutants are as follows: NO_2, SO_2, CO, hydrocarbons, and particulates.

(2) BEST AVAILABLE CONTROL TECHNOLOGY (BACT) - Under the New Source Review rules "BACT" is defined as the best abatement technology which is known for any equipment, but not necessarily in use. Since this is an extremely stringent view of the term BACT, the ARB has recently prepared a list of "BACT" for different types of equipment, and plans to keep the list up to date as new abatement technologies evolve.

(3) AIR QUALITY ANALYSIS means evaluating impacts of new or modified sources on local and regional air quality using applicable models acceptable to the EPA and the ARB.

C. EMISSION OFFSET AND TRADE-OFF POLICY

On December 21, 1976, the EPA issued an interpretative ruling for emission offset or trade-off policy in order to allow further industrial growth in non-attainment areas. In this ruling, emission reductions (offsets) from existing sources in the area of a proposed new source are required such that the total emissions are less, after construction of the new source, than the total allowable emissions from the existing sources were prior to the construction of the new source. These emissions reductions must represent reasonable progress towards attainment of the applicable NAAQS. The EPA has mentioned that they will not question the reviewing authority's judgment as to what constitutes reasonable progress toward attainment, so long as the emission offset results in an overall reduction. Under EPA guidelines the offset for hydrocarbons may be obtained anywhere in the air basin, but the offsets for NO_x, SO_2, particulates, and carbon monoxide should be obtained in the vicinity of the proposed new source.

Section (d) of the Model New Source Review, consideration of further emission reductions, allows the weighing of any trade-off resulting from reductions in the emission of the same air contaminant which are due to the elimination or modification of other existing stationary sources under the same ownership and operating within the same air basin. Meanwhile, part of the Model NSR rules in California have been interpreted to mean that air trade-offs between different companies would be permitted.

California is the first state that has attempted to set up consistent statewide procedures for air trade-offs. On February 10, 1977, Victor Calvo, who chairs the Assembly Committee on Resources, Land Use, and Energy, introduced an air trade-off bill, Assembly Bill 471 (AB 471) (Reference 47). The most recent version (August 5, 1977) of the California trade-off bill leaves much of the decision making on specific issues to individual air pollution control districts. This, therefore, continues the policy of giving local, rather than state government, primary control over stationary source of pollution. Here it is helpful to review specific issues involved in implementing air trade-offs and major uncertainties along with provisions of the current version of AB 471.

Calculating Air Trade-offs

How is the amount of pollution available for trade-offs to be calculated? Is it to be based on an existing facility's actual emission, or its allowable emissions? The issue arises because some facilities are not currently polluting to the maximum extent allowed by law. The present version of AB 471 specifies that trade-offs will be based on actual or allowable pollution, whichever is less (Reference 47). In any event, defining a source's actual emission remains a problem.

As noted, EPA regulations state that each trade-off must have the effect of improving air quality. That is, the reduction in pollution must exceed the added pollution emitted by the new source - but how much greater must it be, i.e., how much must air quality be improved?

The California trade-off bill (AB 471) requires each APCD to devise its own formula for setting trade-off factors, taking into account the severity and frequency of violations of the particular air quality standard. In the case of the Sohio project, the SCAQMD proposed a trade-off factor of 2 to 1 on an annual basis and a 1.2 to 1 on a maximum daily basis for all pollutants.*

The Geographic Boundaries

How far away can the new facility reach to obtain trade-offs? The state bill originally specified a five-mile radius but later adopted a proposal allowing trade-offs outside the immediate vicinity of the new source. However, the local districts must make a finding that a trade-off will not result "in any substantially adverse impact on the ambient air quality" in the immediate vicinity of the new source. In the case of the Sohio project, the SCAQMD proposed a trade-off in the vicinity of the proposed project for all pollutants except hydrocarbons, for which they have accepted a regional trade-off (Reference 48).

*Personal communication, R. MacKnight, South Coast Air Quality Management District, April 7, 1978.

APPENDIX I

ECONOMIC METHODOLOGY

I. LIFE-CYCLE COST APPROACH

The basic structure of the life-cycle cost model is shown in Figure 1. The economic factors have been divided into two groups: "General Model Factors" constitute the generic aspects of the model and include variables that apply to all of the firms; "Site-Specific Factors" consist of site-specific variables that reflect the individual cogeneration systems and the financial aspects of each plant.

In addition to computing the life-cycle cost for a system, the model also computes for a specified year the present value of all revenues associated with the system under consideration. For a cogeneration system, the revenues will consist of the receipts from electricity sales when there is excess by-product electricity available for sale. Since the primary benefits from a cogeneration installation arise from a reduction in annual operating costs, when compared to a non-cogeneration or base system, the revenues from such a system are not necessarily expected to offset the life-cycle cost of the system to yield a positive net present value. Thus, the term "net present cost" is introduced and defined to be the life-cycle cost of the system less the net present value of the receipts from the sale of electricity.

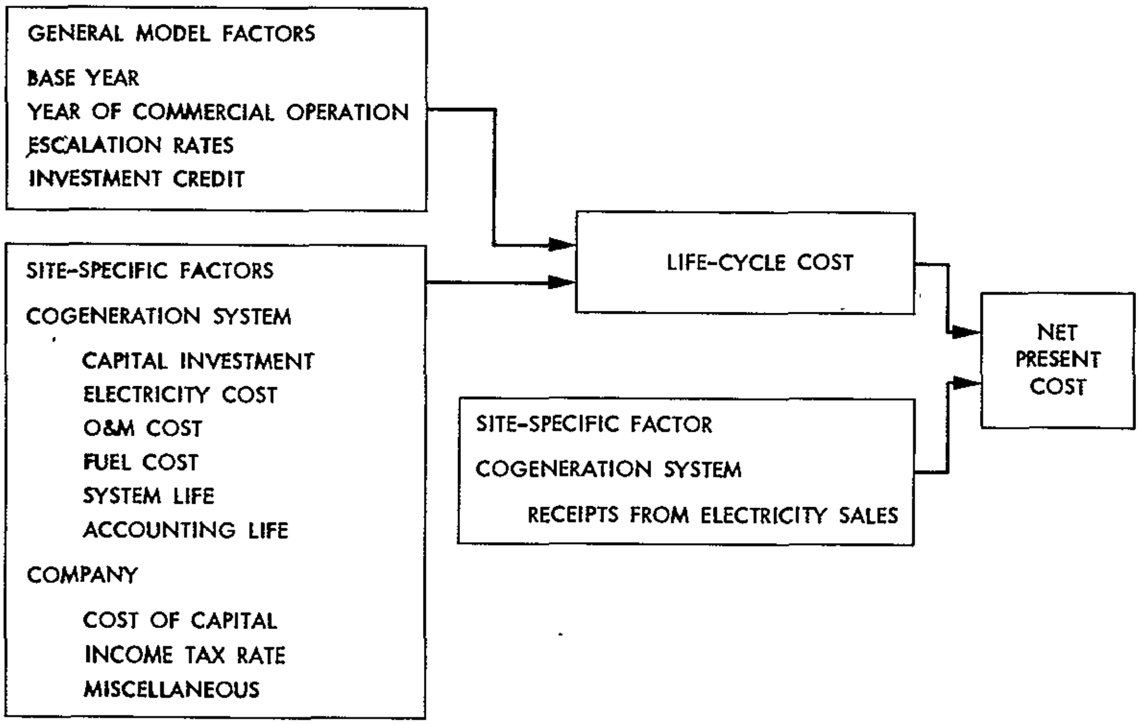

Figure 1. Basic Structure of Life-Cycle Cost Model

II. METHOD OF ANALYSIS

The cost trade-offs of cogeneration are evaluated by the life-cycle cost for a base system without cogeneration with both the life-cycle cost and net present cost, when applicable, of a cogeneration system. Sensitivity analyses are then performed to test the sensitivity of the results to fuel and electricity escalation rates. In addition, the incremental internal rate of return is calculated for each cogeneration system relative to the respective base systems and two financial incentive schemes are evaluated. All assumptions used in the analysis are discussed in Appendix J and all data for each site are enumerated in Appendix K.

III. COMPUTATIONS

The methodology used is a required revenue analysis which is based on the model described in The Cost of Energy From Utility-Owned Solar Electric Systems (JPL 5040-29, ERDA/JPL-1012-76/3), denoted hereafter as USES. While the USES model was developed for utility ownership of solar-electric systems, the model can be applied to a variety of systems including cogeneration systems. The computational structure of the computer model follows the generalized model described in Appendix H of the USES document, which allows the inclusion of tax preference in the form of accelerated depreciation and/or an investment tax credit. The computations that are performed are discussed in detail below. All variable names used in the following equations are defined at the end of this appendix.

A. CAPITAL RECOVERY FACTOR

The capital recovery factor (CRF) represents the uniform annual payment, as a fraction of the original principal, necessary to fully amortize a loan over a specified period of time. The equation is

$$CRF = \frac{R}{1 - (1 + R)^{-N}} \qquad R \neq 0$$

and

$$CRF = \frac{1}{N} \qquad R = 0$$

where N is the system lifetime assumed to be the amortization period and R is the discount rate.

B. ANNUALIZED FIXED CHARGE RATE

The annualized fixed charge rate (FCR) computed by the program is generalized to allow the inclusion of a tax preference. The equation used is

$$FCR = CRF * \left(\frac{1 - (TAX * DPF) - TXCDT}{x - TAX}\right) + BETA$$

where DPF is the depreciation factor (explained below) and TXCDT is the investment tax credit. (Note that the variable TAX is a rate.) The depreciation factor is dependent on the depreciation method, the accounting lifetime (ALIFE) of the system, which may be different from the system lifetime, and the discount rate. The first step to determining the depreciation factor is to compute the accounting capital recovery factor (ACRF). This is computed using the same equations that were used for the CRF discussed above except the accounting lifetime is used in place of the system lifetime. The depreciation factor is then computed according to the following equations.

For the straight line depreciation method

$$DPF = \frac{1}{(ALIFE * ACRF)}$$

For the sum-of-the-years-digits depreciation method

$$DPF = \frac{2 * \left[ALIFE - \left(\frac{1}{ACRF}\right)\right]}{ALIFE * (1 + ALIFE) * R} \qquad R \neq 0$$

$$DPF = 1 \qquad R = 0$$

For the cogeneration analysis, the sum-of-the-years digits depreciation method is assumed.

C. PRESENT VALUE AMOUNTS

The present value amounts of the various cash flows are computed using the basic equations developed in the USES document. In addition, some of the equations are presented in their intermediate stages in order to provide clarification for a more logical analysis of the printed output.

Present Value of Capital Investment

The capital investment is expressed in base year dollars. The present value of the capital investment, in year-of-commercial-operation dollars, is computed by escalating the amount using the following equation

$$CIPV = CI * (1 + GCI)^{(YCO-YB)}$$

After the present value of capital investment is computed, those amounts which have the effect of reducing the CIPV in determining the life-cycle cost of the system are computed.

Tax Reduction (Depreciation)

The effect of tax-deductible depreciation is to reduce income tax liability by reducing taxable income. The present value of the depreciation claim is computed using the equation

Tax Reduction (Depreciation) = TAX * DPF * CIPV

where the variable TAX is the tax rate.

Tax Reduction (Investment Credit)

The introduction of an investment tax credit also has a reducing effect on the CIPV. The effective reduction is computed using the equation

Tax Reduction (Investment Credit) = TXCDT * CIPV

Amortized Investment

Together, the two tax reductions, when subtracted from the capital investment present value, yield the overall effective amount of the original investment, in present value terms, that must be recovered through fixed charges. This amount is the amortized investment.

2. Other Capital Related Charges (Insurance, Property Taxes, Etc.)

Other payments, such as property taxes and insurance premiums, can be approximated as constant multiples of the present value of the total capital investment. These payments are included in the determination of the life-cycle cost of the system and are computed using the equation

Other Capital Related Charges = BETA * CIPV

3. Income Tax Payments

Income tax payments must also be included in the determination of the life-cycle cost of the system. These payments are computed based on an adjustment to the amortized investment which reflects the pre-tax revenue necessary to amortize a given amount with after-tax dollars. The adjustment is computed using the equation

$$\text{Adjustment} = \frac{1}{1 - \text{TAX}} * (1 - \text{TAX} * \text{DPF} - \text{TXCDT}) * \text{CIPV}$$

The income tax payments are then computed

Income Tax Payments = ADJUSTMENT * TAX

In both of these equations, the variable TAX is the tax rate.

4. Electricity, O&M, and Fuel Costs

These costs represent recurrent costs associated with the system operation which occur throughout the system lifetime. Each cost value is input in base year dollars, and must first be escalated to year-of-commercial-operation dollars before the present value is computed. The equations used are

$$\text{Escalated Annual Cost} = \text{AMT} * (1 + G_x)^{(YCO-YB)}$$

where

AMT = electricity, O&M, or fuel recurrent costs or annual receipts from the same of by-product power

G_x = escalation rate for the category of recurrent costs

and

$$\text{Present Value} = \text{Escalated Annual Cost} * N \qquad R = G_x$$

$$\text{Present Value} = \text{Escalated Annual Cost} * \frac{1 + G_x}{R - G_x} * \left[1 - \left(\frac{1 + G_x}{1 + R}\right)^N\right] \qquad R \neq G_x$$

When a stream of annual costs is input, the present value is computed as follows

$$\text{Present Value} = \sum_{j=1}^{N} \text{AMT}(j) * \frac{(1 + G_x)^{(j + YCO-YB)}}{(1 + R)^j}$$

D. SYSTEM LIFE-CYCLE COST

The system life-cycle cost is computed as the sum of the present value amounts described above. This calculation differs in form from the USES document but the net result is the same. The primary difference is that the various components which affect the capital investment present value are computed separately in the program so that they may be separately documented; they are computed simultaneously in the USES model.

E. ANNUALIZED SYSTEM RESULTANT COST

The annualized system-resultant cost is computed by multiplying the life-cycle cost by the capital recovery factor. This amount represents a uniform annual cost that has exactly the same present value as the summed present values of all the separate cost distributions.

F. RECEIPTS FROM SALE OF EXCESS POWER

These receipts represent the annual revenue expected from the sale of by-product power throughout the system lifetime. The present value is computed in the same manner as for the recurrent costs of the system.

G. NET PRESENT VALUE

The net present value of the system is the difference between the present value of the system revenues and the present value of the system costs.

IV. DEFINITIONS OF VARIABLES

YB	base year
YCO	year of commercial operation
N	system lifetime
R	discount rate
TXCDT	investment tax credit
TAX	income tax rate
BETA	insurance, other taxes, etc.
ALIFE	accounting lifetime for system
CI	capital investment
GCI	capital escalation rate
ELC	annual electricity charges
GELC	electricity escalation rate
OM	annual O&M charges
GOM	O&M escalation rate
FL	annual fuel cost
GFL	fuel escalation rate
RC	annual receipts from electricity sales
GRC	receipts escalation rate

APPENDIX J

STANDARD SET OF ECONOMIC ASSUMPTIONS FOR COMPARATIVE ANALYSES

I. GENERAL MODEL FACTOR ASSUMPTIONS

General model factors are those factors that reflect general economic conditions. Normally, the values used for these factors are used for every site, except for fuel escalation rates where the rate differs for different fuel types.

Base Year (YB). The costs and prices input to the model are in terms of constant dollars which correspond to the current dollar price as of January 1, 1977.

Year of Commercial Operation (CO). All present value amounts and output values are computed in the year of commercial operation. The analysis for this study assumed that the cogeneration system is operational by December 31, 1977. In actuality, the complete installation of a cogeneration system can take from one to three years.

Escalation Rates (G_X). Escalation rates, or growth rates, represent the rate of increase for a category of expenditures, or revenues, and include both the rate of inflation and the rate of real growth. These rates are used in the life-cycle cost model to calculate the present value for a stream of expenditures or revenues, over time, in a given category.

Not all possible escalation rates are needed for this analysis. A capital escalation rate does not enter into the computations because of the assumption that the cogeneration system is installed and operational in one year. A general inflation rate is implicitly included in the escalation rates.

The selection of the proper escalation rates is difficult at best and often results in controversy. Many assumptions are built into various forecasting models and the resulting rates are only as valid as the assumptions. Data Resources, Inc. (DRI), in its Energy Review, Summer 1977, presents four different forecasts based on four different sets of assumptions. For this study, the assumptions used for the DRI Control Case are considered to be reasonable and the forecasted escalation rates have been used as a baseline. Following is a list of the escalation rates used in the analysis accompanied by an explanation of the source for each.

Electricity Escalation Rate (GELC). This rate is used in conjunction with the cost of electricity to the firm and also the price the utility will be willing to pay for surplus power the firm wishes to

sell. The "Average Industrial Electricity Prices" from the DRI Control Case for the Pacific Region predicts the following annual percent change over three five-year periods:

Period	Annual % Change
1975-1980	12.1
1980-1985	10.4
1985-1990	8.8

This corresponds to an average annual rate of 10.43%. For the analysis, this figure is rounded to 10.5%.

Fuel Escalation Rate (GFL). This rate is used in conjunction with the cost of fuel to the firm. Five different fuel types were reported in the site reports: natural gas, fuel oil, coal, hog fuel, and refinery fuel gas. The cogeneration systems utilizing either coal or refinery fuel gas do not require any increase in fuel consumption; thus, the fuel costs and the corresponding escalation rates are not included in the analysis.

Natural Gas. The "Average Industrial Natural Gas Prices" from the DRI Control Case for the Pacific Region predicts the following annual percent change over three 5-year periods:

Period	Annual % Change
1975-1980	6.2
1980-1985	10.1
1985-1990	6.8

This corresponds to an average annual rate of 7.69%. For the analysis, this figure is rounded to 7.5%.

Fuel Oil. The "Price of Oil to Electric Utilities" from the DRI Control Case for the Pacific Region was used to determine this rate because data were not available for the average industrial fuel oil prices. A high correlation between the industrial and utility natural gas prices exists and it was assumed that a similar correlation exists for fuel oil. The predicted annual percent change over three 5-year periods is:

Period	Annual % Change
1975-1980	9.0
1980-1985	9.5
1985-1990	7.0

This corresponds to an average annual rate of 8.59%. For the analysis, this figure is rounded to 8.5%.

Hog Fuel. Hog fuel probably compares most nearly to the use of coal as a fuel because of various pollution requirements. Thus, the escalation rate determined for coal was used as a surrogate for the hog fuel escalation rate.

The "National Energy Prices" for contract delivered coal from the DRI Control Case was used to determine this rate. This data included transportation charges. The predicted annual percent change over three 5-year periods is:

Period	Annual % Change
1975-1980	8.2
1980-1985	5.5
1985-1990	4.3

This corresponds to an average annual rate of 5.99%. For the analysis, this figure is rounded to 6.0%.

Operations and Maintenance Escalation Rate (GOM). This rate is used in conjunction with the cost of operations and maintenance, excluding fuel cost. The components of the O&M costs are broken down into the following categories:*

Water	5%
Chemical	26%
Electrical	34%
Labor	19%
Parts	16%

To obtain an escalation rate for this factor, a composite rate was constructed based on the DRI Outlook for the United States Energy Sector: Control Base Forecasts.

Gross National Product (GNP) deflator predictions were used to estimate the water portion; the Wholesale Price Index (WPI) predictions were used to estimate the chemical and parts portion; the Adjusted Average Hourly Earnings prediction was used for the labor portion; and the electricity escalation rate discussed previously was used for the electrical portion. The predicted annual percent change over three 5-year periods and the calculated results for each are shown below:

*Personal communication, Clayton Manufacturing Company.

Period	Annual % Change GNP Deflator	Annual % Change WPI	Annual % Change Adjusted Hourly Earnings	Annual % Change Electricity
1975-1980	5.6	5.9	7.1	12.1
1980-1985	3.5	4.5	6.8	10.4
1985-1990	3.0	3.1	5.9	8.8
Average rate	4.0	4.49	6.6	10.43
Rounded rate	4.0	4.5	6.5	10.5

The weighted average of these rates was then computed to obtain a value of 6.89% which is rounded to 7%. This figure is used as a surrogate for the O&M escalation rate.

Investment Tax Credit. An investment tax credit of 10% is assumed to coincide with current tax laws.

II. SENSITIVITY TO PRICE ESCALATION RATES

The assumed price escalation rates are:

Electricity	10.5%
Natural gas	7.5%
Fuel oil	8.5%
Hog fuel	6.0%

How sensitive are the analyses to these escalation rates? If the assumed escalation rate is in error by as much as 15% in either direction, would the outcome of the analyses be different?

A. SENSITIVITY TO ELECTRICITY PRICE ESCALATION RATE

The sensitivity of the life-cycle cost of the cogeneration system to a range of electricity escalation rates from 9% to 12% was tested. Seven of the 12 firms were found to be more sensitive to the electricity escalation rate than to the fuel escalation rate. The seven are:

California Portland Cement Co.
Exxon Co., U.S.A.
Kaiser Steel Corp.
Owens-Illinois, Inc.

Simpson Paper Co.
Simpson Timber Co.
Union Oil Co.

All seven of these industrial firms utilize captive energy sources for the cogeneration systems, significantly reducing or eliminating additional fuel costs. Simpson Paper Company and Simpson Timber Company utilize a wood waste product, hog fuel, as a fuel source for their cogeneration systems; the remaining firms utilize various forms of waste heat. For these firms, then, because electricity prices are expected to increase at a faster rate than fuel prices, the economic viability of the cogeneration system will improve.

The sensitivity of the life-cycle cost to the electricity escalation rate for the base system and the cogeneration system was tested for each site. There were no sites for which a wrong choice in the electricity escalation rate would result in an incorrect choice being made between the base system and the cogeneration system.

B. SENSITIVITY TO FUEL PRICE ESCALATION

The remaining five industrial firms are more sensitive to fuel price escalation than to electricity price escalation. The five are:

California Paperboard Corp.
Hunt-Wesson Foods, Inc.
Husky Oil Co.
Kelco Co.
Spreckels Sugar Co.

Of these five, only Spreckels Sugar has a life-cycle cost for the cogeneration system that is lower than the base system life-cycle cost. For these firms, the economic viability of the cogeneration systems is not likely to improve because the cogeneration system requires more fuel than the base system.

The sensitivity of the life-cycle to the fuel price escalation for the base system and the cogeneration system was tested for each site.* A wrong choice for the fuel price escalation rate does not affect the choice of the cogeneration system over the base system for the four remaining firms; the incremental difference between the two alternatives is larger than could be overcome by a significant change in the fuel escalation rate. Thus, the outcome of the analysis would not be effected by an error in the fuel escalation rate.

*Only those cogeneration systems requiring additional fuel for cogeneration were evaluated.

III. SITE-SPECIFIC FACTOR ASSUMPTIONS

A. COGENERATION SYSTEM ECONOMIC PROPERTIES

Capital Investment. The capital investment for each site-specific cogeneration system was estimated using Figures 3.10, 3.11 and 3.14 in Reference 49. The cost figures, in kW of capacity, were reported in 1975 dollars using a 6% rate of escalation. The escalated cost was then multiplied by the proposed capacity of the particular cogeneration system.

The cost estimates* for gas turbine topping systems include installation labor, accessory equipment and piping, foundations, building, instruments, insulation, painting, indirect costs, and distributable costs. For steam turbine topping systems the cost estimates include the installed cost of the boiler, steam turbine, fuel handling and pollution control equipment. Pollution control equipment and fuel handling costs are excluded from estimates when the existing boiler is utilized in the system. The cost estimates do not include transformers, escalation interest during construction, land, or other owner's costs.

Annual Electricity Costs (ELC). This factor represents the total cost of purchased electricity. For the base case analysis, the reported yearly usage is multiplied by the reported rate. For the cogeneration case analysis, the difference between the yearly usage and the computed cogeneration capacity, when positive, is multiplied by the reported rate.

Annual O&M Costs (OM). The annual O&M costs for the base case, steam boiler systems, were estimated to be 13.4¢ per 1000 pounds of steam generated at 90% efficiency using the following breakdown:**

Water	0.6¢/1000 lb
Chemical	3.5¢/1000 lb
Electrical	4.6¢/1000 lb
Labor	2.5¢/1000
Maint. Parts	2.2¢/1000 lb
Total	13.4¢/1000 lb

The total O&M costs were then calculated based on the average steam load and number of hours of operation for each site.

*Kaiser Steel had estimated a 63 million dollar capital investment would be required. Using the estimating technique described, only 29.7 million was calculated. Evaluations were made using the 63 million dollar capital investment figure.

**Ibid.

The annual O&M costs for the cogeneration system were estimated based on the O&M costs reported in Reference 49. These costs are 0.3¢/kW-h for steam turbine topping and condensing steam turbine bottoming, and 0.4¢/kW-h for gas turbine topping. In most cases, the cogeneration system replaces the steam boiler system and the O&M costs are calculated for the entire system and replace the O&M costs for the steam boiler system. However, in two cases the cogeneration system utilizes the existing steam boiler system so the two O&M costs are added together for the cogeneration system analysis.

Annual Fuel Costs (FL). This factor represents the total cost of fuel required for the production of steam for the base case, and for the production of steam and electricity for the cogeneration case. When the utility owns the cogeneration system, the price paid for steam is also included.

For the base case, the amount of fuel is computed based on the energy rate for the steam demand of the plant calculated in Reference 4. The energy rate is multiplied by the equivalent operating hours and divided by an assumed boiler efficiency of 80% to yield annual fuel consumption is then multiplied by the reported price per MBtu to obtain the annual fuel cost.

For the cogeneration case, the additional fuel required that is chargeable to the power generation was estimated based on Figure 3-1 in Reference 49. The additional fuel costs chargeable to power are added to the base case fuel costs to obtain the annual fuel costs for the cogeneration system. When the utility owns the cogeneration system, the price paid for steam was estimated based on the steam requirements and reported price for steam.

Annual Receipts from Electricity Sales (RC). This factor represents the total receipts from the sale of by-product power. The difference between the computed cogeneration capacity and the yearly usage of electricity, when positive, is multiplied by the reported rate for electricity purchased from the utility.

System Lifetime (N). While the system lifetime for the current boiler system at each site and the proposed cogeneration system may vary, a lifetime of 15 years is assumed in each case. All costs and revenues for the system are computed for a 15-year period.

Accounting Lifetime. The capital expended for cogeneration systems is depreciated over a 10-year accounting life. This assumption tends to make the results of the cogeneration analysis more attractive than if the accounting lifetime were assumed equal to the system lifetime.

B. ECONOMIC STRUCTURE OF COMPANY

Discount Rate (R). This factor reflects the after-tax required return at each site, rather than the cost of capital to the firm. A firm will not invest in a project unless the return, as a minimum, is equal to the cost of capital. Those projects that qualify are then ranked according to priority and/or maximum return. Thus, in evaluating a cogeneration system, the required return is used rather than the actual cost of capital.

Income Tax Rate. A combined state and federal tax rate of 50% is used for each site.

Miscellaneous. This factor includes insurance premiums and other taxes. The amount is calculated as a percentage of the present value of the total capital investment. The rate used for each site is 2.5%.

APPENDIX K

SITE-SPECIFIC ECONOMIC TABLES

Key

"Base" refers to the present method of steam production in the plant. Power is purchased.

Cogeneration System

(1) All cogenerated power is used to offset purchased power. Additional required power is purchased at the base system rate.

(2) All excess by-product power is sold at the base system rate.

(3) All excess by-product power is sold at 14 mills/kW-h.

(4) Both power and steam are purchased.

(5) All cogenerated power is sold at 19.5 mills/kW-h. Required power is purchased at the base system rate.

California Paperboard Corp.: Company owns the cogeneration system.

	Base	Cogeneration System (2)	(3)	(5)
1. Base year	1977	1977	1977	1977
2. Year of commercial operation	1977	1977	1977	1977
3. Escalation rates:				
a. Electricity, %	10.5	10.5	10.5	10.5
b. Fuel, %	7.5	7.5	7.5	7.5
c. O & M, %	7	7	7	7
d. Receipts, %	10.5	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10	10
5. Capital cost, 10^6\$	--	3.7	3.7	3.7
6. Electricity cost, 10^6\$	0.66	--	--	0.66
7. Fuel cost, 10^6\$	1.714	2.515	2.515	2.515
8. O & M cost, 10^6\$	0.071	0.284	0.284	0.284
9. Receipts from electricity sales, 10^6\$	--	0.850	0.536	1.326
10. System life, yr	15	15	15	15
11. Accounting life, yr	--	10	10	10
12. Discount rate, %	12.5	12.5	12.5	12.5
13. Income tax rate, %	--	50	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5	2.5
Life-cycle cost, 10^6\$	27.55	34.52	34.52	43.13
Annualized system resultant cost, 10^6 \$	4.15	5.20	5.20	6.50
Net present cost, 10^6\$	27.55	23.44	27.54	25.84
Break-even price for excess electricity is 1.4¢/kW-h.				

California Paperboard Corp.: Utility owns the cogeneration system.

	Base	Cogeneration System (4)
1. Base year	1977	1977
2. Year of commercial operation	1977	1977
3. Escalation rates:		
a. Electricity, %	10.5	10.5
b. Fuel, %	7.5	7.5
c. O & M, %	7	7
d. Receipts, %	10.5	10.5
4. Investment tax credit, %	--	10
5. Capital cost, 10^6\$	--	--
6. Electricity cost, 10^6\$	0.66	0.66
7. Fuel cost, 10^6\$	1.714	1.696
8. O & M cost, 10^6\$	0.071	--
9. Receipts from electricity sales, 10^6\$	--	--
10. System life, yr	15	15
11. Accounting life, yr	--	10
12. Discount rate, %	12.5	12.5
13. Income tax rate, %	--	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5
Life-cycle cost, 10^6\$	27.55	26.63
Annualized system resultant cost, 10^6\$	4.15	4.01
Net present cost, 10^6\$	27.55	26.63
Break-even price for steam is \$3.39/10^3 lb.		

California Portland Cement Corp.

	Base	Cogeneration System (1)	Cogeneration System (5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	--	--	--
c. O & M, %	--	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10
5. Capital cost, 10^6\$	--	9.1	9.1
6. Electricity cost, 10^6\$	3.0	0.9456	3.0
7. Fuel cost, 10^6\$	--	--	--
8. O & M cost, 10^6\$	--	0.257	0.257
9. Receipts from electricity sales, 10^6\$	--	--	1.667
10. System life, yr	15	15	15
11. Accounting life, yr	--	10	10
12. Discount rate, %	10	10	10
13. Income tax rate, %	--	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5
Life-cycle cost, 10^6\$	46.67	29.55	61.52
Annualized system resultant cost, 10^6\$	6.14	3.89	8.09
Net present cost, 10^6\$	46.67	29.55	35.58

Exxon Co., U.S.A.

	Base	Cogeneration System	
		(1)	(5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	--	--	--
c. O & M, %	--	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10
5. Capital cost, 10^6\$	--	9.4	9.4
6. Electricity cost, 10^6\$	12.0	3.484	12.0
7. Fuel cost, 10^6\$	--	--	--
8. O & M cost, 10^6\$	--	0.852	0.852
9. Receipts from electricity sales, 10^6\$	--	--	4.152
10. System life, yr	15	15	15
11. Accounting life, yr	--	10	10
12. Discount rate, %	12.5	12.5	12.5
13. Income tax rate, %	--	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5
Life-cycle cost, 10^6\$	156.41	66.55	177.54
Annualized system resultant cost, 10^6\$	23.58	10.03	26.78
Net present cost, 10^6\$	156.41	66.55	123.43

Hunt-Wesson Foods, Inc.: Cogeneration system matches steamload of canning season and operations only during canning season ("Canning Season").

	Base	Cogeneration System (2)	Cogeneration System (3)	Cogeneration System (5)
1. Base year	1977	1977	1977	1977
2. Year of commercial operation	1977	1977	1977	1977
3. Escalation rates:				
a. Electricity, %	10.5	10.5	10.5	10.5
b. Fuel, %	7.5	7.5	7.5	7.5
c. O & M, %	7	7	7	7
d. Receipts, %	10.5	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10	10
5. Capital cost, 10^6\$	--	13.7	13.7	13.7
6. Electricity cost, 10^6\$	0.2904	--	--	0.2904
7. Fuel cost, 10^6\$	2.727	4.313	4.313	4.313
8. O & M cost, 10^6\$	0.144	0.649	0.649	0.649
9. Receipts from electricity sales, 10^6\$	--	3.604	2.1028	3.165
10. System life, yr	15	15	15	15
11. Accounting life, yr	--	10	10	10
12. Discount rate, %	10	10	10	10
13. Income tax rate, %	--	50	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5	2.5
Life-cycle cost, 10^6\$	40.46	79.61	79.61	84.13
Annualized system resultant cost, 10^6\$	5.32	10.47	10.47	11.06
Net present cost, 10^6\$	40.46	23.53	46.90	34.89

Break-even price for excess electricity is 1.7¢/kW-h.

Hunt-Wesson Foods, Inc.: Cogeneration system matches steam load of off-season and operates all year ("Alternate 1").

	Base	Cogeneration System (1)	Cogeneration System (5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	7.5	7.5	7.5
c. O & M, %	7	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10
5. Capital cost, 10^6\$	--	0.3	0.3
6. Electricity cost, 10^6\$	0.5	0.3020	0.5
7. Fuel cost, 10^6\$	3.094	3.153	3.153
8. O & M cost, 10^6\$	0.163	0.024	0.024
9. Receipts from electricity sales, 10^6\$	--	--	0.117
10. System life, yr	15	15	15
11. Accounting life, yr	--	10	10
12. Discount rate, %	10	10	10
13. Income tax rate, %	--	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5
Life-cycle cost, 10^6\$	48.56	44.92	48.00
Annualized system resultant cost, 10^6\$	6.38	5.91	6.31
Net present cost, 10^6\$	48.56	44.92	46.18

Hunt-Wesson Foods, Inc.: Cogeneration system matches steamload of canning season and operates all year, dumping steam during off season ("Alternate 2").

	Base	Cogeneration System (2)	(3)	(5)
1. Base year	1977	1977	1977	1977
2. Year of commercial operation	1977	1977	1977	1977
3. Escalation rates:				
a. Electricity, %	10.5	10.5	10.5	10.5
b. Fuel, %	7.5	7.5	7.5	7.5
c. O & M, %	7	7	7	7
d. Receipts, %	10.5	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10	10
5. Capital cost, 10^6\$	--	13.7	13.7	13.7
6. Electricity cost, 10^6\$	0.5	--	--	0.5
7. Fuel cost, 10^6\$	3.094	6.817	6.817	6.817
8. O & M cost, 10^6\$	0.163	1.524	1.524	1.524
9. Receipts from electricity sales, 10^6\$	--	8.695	5.0728	7.428
10. System life, yr	15	15	15	15
11. Accounting life, yr	--	10	10	10
12. Discount rate, %	10	10	10	10
13. Income tax rate, %	--	50	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5	2.5
Life-cycle cost, 10^6\$	48.56	121.62	121.62	129.40
Annualized system resultant cost, 10^6\$	6.38	15.99	15.99	17.01
Net present cost, 10^6\$	48.56	13.65	42.71	13.84
Break-even price for excess electricity is 1.3¢/kW-h.				

Husky Oil Co.: The company purchases steam from the utility and sells oil to the utility.

	Base	Cogeneration System (4)
1. Base year	1977	1977
2. Year of commercial operation	1977	1977
3. Escalation rates:		
a. Electricity, %	10.5	10.5
b. Fuel, %	7.5	7.5
c. O & M, %	7	7
d. Receipts, %	10.5	10.5
4. Investment tax credit, %	--	10
5. Capital cost, 10^6\$	--	--
6. Electricity cost, 10^6\$	0.2	0.2
7. Fuel cost, 10^6\$	20.438	29.5
8. O & M cost, 10^6\$	0.883	--
9. Receipts from electricity sales, 10^6\$	--	2.3
10. System life, yr	15	15
11. Accounting life, yr	--	10
12. Discount rate, %	12	12
13. Income tax rate, %	--	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5
Life-cycle cost, 10^6\$	236.38	326.46
Annualized system resultant cost, 10^6\$	34.71	47.93
Net present cost, 10^6\$	236.38	299.45

Break-even price for excess steam is \$3.26/10^3 lb.

Kaiser Steel Corp.

	Base	Cogeneration System (1)	Cogeneration System (5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	--	--	--
c. O & M, %	--	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10
5. Capital cost, $10^6$$	--	63.0	63.0
6. Electricity cost, $10^6$$	18.0	10.234	18.0
7. Fuel cost, $10^6$$	--	--	--
8. O & M cost, $10^6$$	--	0.773	0.773
9. Receipts from electricity sales, $10^6$$	--	--	5.023
10. System life, yr	15	15	15
11. Accounting life, yr	--	10	10
12. Discount rate, %	15	15	15
13. Income tax rate, %	--	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5
Life-cycle cost, $10^6$$	199.12	204.62	290.53
Annualized system resultant cost, $10^6$$	34.05	34.99	49.69
Net present cost, $10^6$$	199.12	204.62	234.96

Kelco Co.: Company owns the cogeneration system.

	Base	Cogeneration System (2)	Cogeneration System (3)	Cogeneration System (5)
1. Base year	1977	1977	1977	1977
2. Year of commercial operation	1977	1977	1977	1977
3. Escalation rates:				
a. Electricity, %	10.5	10.5	10.5	10.5
b. Fuel, %	7.5	7.5	7.5	7.5
c. O & M, %	7	7	7	7
d. Receipts, %	10.5	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10	10
5. Capital cost, 10^6\$	--	8.2	8.2	8.2
6. Electricity cost, 10^6\$	1.7	--	--	1.7
7. Fuel cost, 10^6\$	4.034	6.359	6.359	6.359
8. O & M cost, 10^6\$	1.59	0.735	0.735	0.735
9. Receipts from electricity sales, 10^6\$	--	4.732	1.893	3.548
10. System life, yr	15	15	15	15
11. Accounting life, yr	--	10	10	10
12. Discount rate, %	15	15	15	15
13. Income tax rate, %	--	50	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5	2.5
Life-cycle cost, 10^6\$	57.01	75.51	75.51	94.31
Annualized system resultant cost, 10^6\$	9.75	12.91	12.91	16.13
Net present cost, 10^6\$	57.01	23.18	54.57	54.66
Break-even price for excess by-product power is 1.2¢/kW-h.				

Kelco Co.: Utility owns the cogeneration system.

	Base	Cogeneration System (4)
1. Base year	1977	1977
2. Year of commercial operation	1977	1977
3. Escalation rates:		
a. Electricity, %	10.5	10.5
b. Fuel, %	7.5	7.5
c. O & M, %	7	7
d. Receipts, %	10.5	10.5
4. Investment tax credit, %	--	10
5. Capital cost, 10^6\$	--	--
6. Electricity cost, 10^6\$	1.7	1.7
7. Fuel cost, 10^6\$	4.034	6.2
8. O & M cost, 10^6\$	0.159	--
9. Receipts from electricity sales, 10^6\$	--	--
10. System life, yr	15	15
11. Accounting life, yr	--	10
12. Discount rate, %	15	15
13. Income tax rate, %	--	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5
Life-cycle cost, 10^6\$	57.01	75.36
Annualized system resultant cost, 10^6\$	9.75	12.89
Net present cost, 10^6\$	57.01	75.36
Break-even price for steam is \$3.18/10^3 lb.		

	Base	Cogeneration System	
		(1)	(5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	--	--	--
c. O & M, %	--	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10
5. Capital cost, $10^6$$	--	3.7	3.7
6. Electricity cost, $10^6$$	3.0	1.888	3.0
7. Fuel cost, $10^6$$	--	--	--
8. O & M cost, $10^6$$	--	0.102	0.102
9. Receipts from electricity sales, $10^6$$	--	--	0.66
10. System life, yr	15	15	15
11. Accounting life, yr	--	10	10
12. Discount rate, %	12	12	12
13. Income tax rate, %	--	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5
Life-cycle cost, $10^6$$	40.47	31.40	46.40
Annualized system resultant cost, $10^6$$	5.94	4.61	6.81
Net present cost, $10^6$$	40.47	31.40	37.50

Simpson Paper Co.

	Base	Cogeneration System (2)	(3)	(5)
1. Base year	1977	1977	1977	1977
2. Year of commercial operation	1977	1977	1977	1977
3. Escalation rates:				
a. Electricity, %	10.5	10.5	10.5	10.5
b. Fuel, %	7.5	6	6	6
c. O & M, %	7	7	7	7
d. Receipts, %	10.5	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10	10
5. Capital cost, 10^6\$	--	8.1	8.1	8.1
6. Electricity cost, 10^6\$	5.9	--	--	5.9
7. Fuel cost, 10^6\$	3.735	0.507	0.507	0.507
8. O & M cost, 10^6\$	0.128	0.7	0.7	0.7
9. Receipts from electricity sales, 10^6\$	--	1.9	0.65	3.27
10. System life, yr	15	15	15	15
11. Accounting life, yr	--	10	10	10
12. Discount rate, %	12	12	12	12
13. Income tax rate, %	--	50	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	2.5	2.5	2.5
Life-cycle cost, 10^6\$	121.94	23.09	23.09	102.67
Annualized system resultant cost, 10^6\$	17.90	3.39	3.39	15.07
Net present cost, 10^6\$	121.94	2.68	14.32	52.49

Break-even price for excess by-product power is less than zero.

Simpson Timber Co.

	Base	Cogeneration System (1)	Cogeneration System (5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	6	6	6
c. O & M, %	7	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10
5. Capital cost, $10^6$$	--	0.14	0.14
6. Electricity cost, $10^6$$	2.15	2.05	2.15
7. Fuel cost, $10^6$$	0.013	0.016	0.016
8. O & M cost, $10^6$$	0.006	0.015	0.015
9. Receipts from electricity sales, $10^6$$	--	--	0.061
10. System life, yr	15	15	15
11. Accounting life, yr	--	10	10
12. Discount rate, %	12	12	12
13. Income tax rate, %	--	50	50
14. Miscellaneous rate (ins. & prop. tax), %	--	25	25
Life-cycle cost, $10^6$$	29.19	28.25	29.47
Annualized system resultant cost, $10^6$$	4.29	4.15	4.33
Net present cost, $10^6$$	29.19	28.25	28.65

Spreckels Sugar Co.

	Hypothetical Base	Cogeneration System (1)	Cogeneration System (5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	7.5	7.5	7.5
c. O & M, %	7	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	--	--
5. Capital cost*, $10^6$$	--	1.2	1.2
6. Electricity cost, $10^6$$	1.176	0.12	1.176
7. Fuel cost, $10^6$$	3.462	0.12	3.462
8. O & M cost, $10^6$$	0.135	0.082	0.135
9. Receipts from electricity sales, $10^6$$	--	--	0.590
10. System life, yr	15	15	15
11. Accounting life, yr	10	--	10
12. Discount rate, %	10	10	10
13. Income tax rate, %	--	--	--
14. Miscellaneous rate (ins. & prop. tax), %	--	--	--
Life-cycle cost, $10^6$$	63.35	51.63	68.06
Annualized system resultant cost, $10^6$$	8.33	6.79	8.95
Net present cost, $10^6$$	63.35	51.63	58.88

*Replacement cost specified in site report is used here.

Union Oil Company

	Base	Cogeneration System (1)	Cogeneration System (5)
1. Base year	1977	1977	1977
2. Year of commercial operation	1977	1977	1977
3. Escalation rates:			
a. Electricity, %	10.5	10.5	10.5
b. Fuel, %	--	--	--
c. O & M, %	--	7	7
d. Receipts, %	10.5	10.5	10.5
4. Investment tax credit, %	--	10	10
5. Capital cost, $10^6$$	--	15.4	15.4
6. Electricity cost, $10^6$$	12.0	2.313	12.0
7. Fuel cost*, $10^6$$	--	--	--
8. O & M cost, $10^6$$	--	1.209	1.209
9. Receipts from electricity sales, $10^6$$	--	--	6.15
10. System life, yr	15	15	15
11. Accounting life, yr	--	10	10
12. Discount rate, %	10	10	10
13. Income tax rate, %	--	50	50
14. Miscellaneous rate (ins. & prop tax), %	--	2.5	2.5
Life-cycle cost, $10^6$$	186.69	70.48	221.18
Annualized system resultant cost, $10^6$$	24.54	9.27	29.08
Net present cost, $10^6$$	186.69	70.48	125.50

*Union Oil has indicated that additional fuel would be required for their cogeneration system.

APPENDIX L

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